OSAGE OPERATOR'S ENVIRONMENTAL REFERENCE MANUAL

US Environmental Protection Agency
Region 6
Bureau of Indian Affairs,
Osage Nation Minerals Council
Osage Nation Executive Branch

DRAFT
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List of Acronyms

BIA	Bureau of Indian Affairs
BMP	Best Management Practices
CAA	Clean Air Act
CAED	Compliance Assurance and Enforcement Division
CDL	Compensated Density Log
CFR	Code of Federal Regulations
CNL	Compensated Neutron Log
CWA	Clean Water Act
E&P	Exploration and Production
EPA	Environmental Protection Agency
H2S	Hydrogen Sulfide
HCl	Hydrochloric Acid
IEL	Induction Electric Log
ISIP	Instantaneous Shut in Pressure
MIT	Mechanical Integrity Test
MSDS	Material Safety Data Sheet
MSS	Maintenance Startup Shutdown
NORM	Naturally Occurring Radioactive Material
NPDES	National Pollutant Discharge Elimination System
P&A	Plug and Abandon
PRD	Pressure Relief Devices
PSIG	Pounds Per Square Inch Gauge (excludes atmospheric pressure)
RCRA	Resource Conservation and Recovery Act
REI	Radius of Endangering Influence
SDWA	Safe Drinking Water Act
SPCC	Spill Prevention Control and Countermeasures
TDS	Total Dissolved Solids
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
USEPA	United States Environmental Protection Agency
VOC	Volatile Organic Compounds
VRU	Vapor Recovery Units
ZEI	Zone of Endangering Influence

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Preface

In 1997, Environmental Protection Agency (EPA) and the Bureau of Indian Affairs (BIA) worked with certain parties to develop an Osage Operator's Handbook that provided a clear language interpretation of the regulations and discussed best management practices for oil and gas operations within Osage County to assist with compliance of environmental laws and regulations. The Handbook now needs revisions to incorporate regulatory changes given changes in the law. EPA and BIA plan to revise and update the Handbook in conjunction with the Osage Minerals Council, Nation Representatives, and identified stakeholder groups.

Revision of the Handbook is intended to provide guidance on how to comply with current environmental laws and the regulations governing oil and gas operations within Osage County. The Handbook will also provide clarification on which agencies should be contacted in the event someone has concerns regarding those oil and gas operations. The objective of the Handbook is to provide useful guidance and best management practice standards for daily responsibilities concerning oil and gas operations.

The Handbook is not intended to provide legal advice, replace existing legal obligations with respect to environmental responsibilities or oil and gas operations within Osage County or establish new rules or regulations. The Handbook will not, nor is it intended to, address all processes, procedures and aspects of applicable laws and regulations that govern Osage County.

Contact Information

To Report:	Contact:
• Saltwater (Brine) Spills • Air Quality Concerns • Hazardous Waste Concerns • Drinking Water Concerns • Discharges to waterways (such as creeks, streams, rivers, lakes, ponds) • Fish Kills and Wildlife Concerns • Any other concerns regarding oil and gas operations or lease compliance	BIA Hotline: **918- 287-3107**
Chemical release or oil spill which enters or threatens to enter a waterway (such as a creek, stream, river, lake or pond)	REPORT IMMEDIATELY to National Response Center **1-800-424-8802** IMPORTANT: Operators are **required** to immediately report oil spills from their facilities to the National Response Center. Reporting to any other number will not meet federal reporting requirements in the Clean Water Act.

WATER POLLUTION PREVENTION

SURFACE WATER QUALITY PROTECTION

What laws and regulations regarding water quality are applicable to oil and gas activities on the surface?

A. The Clean Water Act

The U.S. Clean Water Act (CWA) is the cornerstone of surface water quality protection in the United States. The CWA protects designated waters in the United States through implementing regulations, permits, and the law. The Clean Water Act was established to restore and maintain the chemical, physical, and biological integrity of the nation's waters. The CWA aims to protect water quality through development of water quality standards, anti-degradation policies, water quality permitting procedures, water body monitoring and assessment programs, and elimination or point and nonpoint pollution sources. The CWA also makes it unlawful to discharge any pollutant from a point source into waters of the United States.

EPA implements and enforces the Clean Water Act applicable to onshore oil and gas exploration and production activities.. Applicable sections include:

1. **Section 301** – Prohibits the unauthorized discharge of pollutants into waters of the United States. Determining whether a water body meets that definition is a complex legal and technical determination made on a case by case basis. Oil and gas operators should not discharge to any surface water body.

2. **Section 308** - Provides the EPA with the ability to inspect facilities and to require submission of sampling information.

3. **Section 309 -** Provides the EPA with authority to enforce the CWA including issuing administrative orders, administrative penalties, or initiating civil action for violations of the CWA.

4. **Section 311** - Prohibits the discharge of oil or hazardous substances into waters of the U.S. in such quantities as may be harmful and provides for spill prevention requirements, spill reporting obligations, and spill response planning and authorities. This section regulates the prevention and response to accidental releases of oil and hazardous substances into navigable waters, on adjoining shorelines, or affecting natural resources belonging to or managed by the United States.

B. EPA's Osage Brine Program

EPA Region 6 operates an oil field brine program focused on the unauthorized discharge of oilfield brine (produced waters). Produced water is an industrial waste and is defined as a pollutant under the Clean Water Act (CWA). Produced water is typically high in salts and is commonly referred to as oil field brine or brine. Since produced water is high in salts it is extremely toxic to a fresh water ecosystem or environment. EPA effluent guideline regulations prohibit the discharge of produced waters.

Does EPA monitor brine discharge activities?

Yes, EPA conducts inspections at oil and gas facilities under the authority of Section 308 of the CWA. Often, when the EPA conducts an inspection at an oil and gas facility the facility representative is usually not present. During the inspection the EPA is looking for produced water discharges from the facility which are a violation of the CWA. A discharge is considered any release of a pollutant(s) from a facility, which also includes accidental spills.

How will the facility or a landowner be made aware that an inspection has been conducted?

Effective October 1, 2013 EPA posts copies of all inspection reports to our Region 6 web site at http://www.epa.gov/region6/6en/public.html . Prior to posting the facility operator is provided a 10 day review period.

How else may EPA obtain information about a suspected spill?

Under Section 308 of the CWA the EPA may make efforts to obtain additional information about a facility with a formal information request. Information requests will typically seek information about a discharge from the facility.

Does EPA have any enforcement authority for these types of spills?

The EPA may pursue enforcement actions pursuant to Section 309 as the result of an inspection or from a response to an information request. If a produced water discharge from an oil and gas facility has been identified and it is determined by the EPA that it reaches surface waters this is a violation of the CWA. Under these circumstances the EPA may pursue an enforcement action. Enforcement actions are typically in the form of civil enforcement which includes both administrative and judicial actions. Administrative enforcement actions are in the form of administrative orders and administrative penalty orders.

What types of corrective actions are included in these AOs?

Administrative orders (AO) orders the facility to come back into compliance with the CWA by performing certain corrective action(s). Typically for an unauthorized brine discharge the correction actions required by the alleged violator will include but are not limited to the following: cease the discharge; remove the pollutant from the impacted water body; if necessary remove contaminated soils to prevent future discharge of pollutants and to submit information documenting that the requirements of the AO have been met. In cases where there is significant environmental harm or if the discharge is not properly remediated administrative penalties (APO) or administrative complaints may also be pursued by the EPA as a result of a violation or violations of the CWA.

How can I see if a facility has been issued an Order?

EPA posts copies of all administrative actions taken and you may also access this information at the website listed above.

C. Spill Prevention Control and Countermeasures (SPCC)

The purpose of the Spill Prevention, Control, and Countermeasure (SPCC) rule is to help facilities prevent a discharge of oil into navigable waters or adjoining shorelines. This rule is part of the EPA's oil spill prevention program and was published under the authority of Section 311(j)(1)(C) of the Federal Water Pollution Control Act (Clean Water Act) in 1974. The rule may be found at Title 40, Code of Federal Regulations, Part 112. These regulations set forth requirements for prevention of, preparedness for, and response to oil discharges at specific non-transportation-related facilities.

To prevent oil from reaching navigable waters and adjoining shorelines, and to contain discharges of oil, the regulation requires certain facilities to develop and implement Spill Prevention, Control, and Countermeasure (SPCC) Plans and establishes procedures, methods, and equipment requirements. Also known as SPCC regulations, the purpose of these regulations are to help facilities prevent a discharge of oil into navigable waters or adjoining shorelines.

Definitions

1. Production facility means all structures (including but not limited to wells, platforms, or storage facilities), piping (including but not limited to flowlines or intra-facility gathering lines), or equipment (including but not limited to workover equipment, separation equipment, or auxiliary non-transportation-related equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of oil (including condensate), or associated storage or measurement, and is located in an oil or gas field, at a facility.

2. Discharge includes but is not limited to, any spilling, leaking, pumping, pouring, emitting, emptying, or dumping of oil.

What are my responsibilities for reporting accidental oil spills?

Immediately report any oil spill which enters or threatens to enter a water body directly to the National Response Center at **1-800-424-8802**. This is an operator liability and cannot be satisfied through any other reporting mechanisms.

Who is covered by the SPCC Rule?

A facility is covered by the SPCC rule and is required to have an SPCC plan if it has an aggregate aboveground oil storage capacity greater than 1,320 U.S. gallons or a completely buried storage capacity greater than 42,000 U.S. gallons and there is a reasonable expectation of an oil discharge into or upon navigable waters of the U.S. or adjoining shorelines.

What if I have underground storage tanks?

You need an SPCC Plan if you have a total underground buried storage capacity of greater than 42,000 gallons of oil; and you could reasonably be expected to discharge oil into or upon the navigable waters of the United States or adjoining shorelines, due to their location.

When does my existing facility need to have an SPCC plan?

Facilities put into service on or before August 16, 2002 must maintain their existing SPCC Plan and review, amend and implement the SPCC Plan no later than November 10, 2011. If your facility was placed into service after August 16, 2002, you must have prepared and implemented an SPCC Plan no later than November 10, 2011.

What if my facility was put into service after November 10, 2011?

For facilities placed into service after November 10, 2011, an SPCC plan must be prepared and implemented within six months after beginning operations.

May I have a drain pipe to drain uncontaminated rainwater from my containment area?

In Osage county, there is a general prohibition of drain pipes with some exceptions. Drain pipes are allowed only with a permit that specifically approves their use.

What are the conditions for use of a drain pipe if allowed to be installed?

The bermed area or pit must be kept clean and any releases of oil inside the containment must be cleaned up immediately. The drain pipe, if permitted, must have a valve and a lock in place to discourage indiscriminate or accidental opening of the valve.

What guidelines are used to determine when I may discharge uncontaminated rainwater from my containment area?

Inspect the retained rainwater to ensure that its presence will not cause a discharge as described in § 40 112.1(b) prior to drainage. Any accumulated oil on the surface of the rainwater must be removed and returned to storage or disposed of in accordance with legally approved methods. In addition, he fluid to be drained must have a otal Dissolved Solids (TDS) of less than 1000 ppm. Open the bypass valve and reseal it following drainage under responsible supervision and keep records of all drainage events.

Am I required to keep records of planned releases?

Each time fluid is drained from the tank it must be documented and this information must be made available during inspections by the BIA Osage Agency, or UIC personnel. The report will include: source, date and time of release; volume of rainfall drained; verification of TDS and absence of free oil. The drain pipe privilege will be revoked if any violation of the guidelines is observed.

How is required containment size determined?

Construct all tank battery, separation, and treating facility installations, so that you provide a secondary means of containment for the entire capacity of the largest single container and sufficient freeboard to contain precipitation.

Are their requirements for pumps and flowlines associated with the tank battery?

Yes, you must prepare and implement a flowline maintenance program. The maintenance program must ensure that flowlines and gathering lines are compatible with the type of production fluids, their corrosivity, volume, and pressure, and other conditions expected.

a. Visually inspect and/or test flowlines and gathering lines and associated equipment on a regular schedule for leaks, oil discharges, corrosion, or other conditions that could lead to a discharge.

b. the frequency and type of testing must allow for the implementation of a contingency plan as described in the attachment for flowlines and gathering lines that are not provided with secondary containment; and

c. Take action and make repairs to any flowlines and gathering lines and associated equipment as identified by inspections, tests, or evidence of a discharge;

d. Promptly remove or/and clean up any oil discharges associated with flowlines, gathering lines, and associated equipment.

Who must develop my SPCC plan?

A Registered Professional Engineer must review and certify each SPCC Plan. A suggested SPCC Plan format is found in Appendix A of this document

Where is my SPCC plan to be kept?

Onshore production facilities must maintain a complete copy of the Plan at the facility, if the facility is normally attended at least four hours per day, or at the nearest field office if the facility is not so attended, and have the Plan available for on-site review during normal working hours.

How often must my plan be reviewed?

A Professional Engineer is required to review each SPCC Plan every 5 years and the SPCC Plan must be amended within 6 months of revision, if applicable.

Plans must also be reviewed when required by the EPA after review of the Plan or whenever there is a change in facility design, construction, operations, or maintenance which materially affects the potential for an oil spill.

When will I be required to submit my SPCC plan to EPA and BIA?

The operator must submit the information below to EPA and to the BIA Osage Agency whenever a facility has:

a. Discharged more than 1,000 U.S. gallons (approximately 24 barrels) of oil into navigable waters in a single spill event; or

b. Discharged more than 42 U.S. gallons (one barrel) of oil into navigable waters in two reportable spill events within any 12-month period.

c. The operator must submit the following to the EPA Regional Administrator and the BIA Osage Agency within 60 days of the occurrence of either of the above two conditions:

1. Name of facility;
2. Your name;
3. Location of facility;
4. Maximum storage capacity of the facility and current normal throughput;
5. Corrective action and countermeasures you have taken, including a description of equipment repairs and replacements;
6. An adequate description of the facility, including maps, flow diagrams, and topographical maps, as necessary;
7. The cause of the discharge as described in § 112.1(b);
8. Additional preventive measures taken to prevent this from happening again; and;
9. Any other information the EPA Region or BIA Osage Agency requests.

What type of training should my employees receive on SPCC requirements?

a. Train your oil-handling personnel in the operation and maintenance of equipment; discharge procedures; applicable rules and regulations; general facility operations; and the SPCC Plan.

b. Designate a person at each facility who is accountable for SPCC and who reports to facility management.

c. Schedule and conduct discharge prevention briefings for your oil-handling personnel at least once a year to assure adequate understanding of the SPCC Plan. Briefings must cover spills, failures, malfunctioning components.

Am I required to conduct inspections and maintain records?

Conduct inspections and tests of the facility, in accordance with written procedures developed for the facility. You must keep these records, signed by the appropriate supervisor, with the SPCC Plan for a period of three years.

What happens if I violate the SPCC requirements?

Owners and operators of facilities who violate the requirements of the regulations relating to preparation, implementation, and amendments to SPCC Plans are liable for a civil penalty of not more than $25,000 for each day such violation continues.

Who should I contact for more information about SPCC requirements?

U.S. EPA Region 6
1445 Ross Ave. (6SF-RO)
Dallas, TX 75202-2733
214-665-6444

You may find more information at:
http://www.epa.gov/oem/content/spcc/index.htm

This guidance is a brief summary of the SPCC Regulations and provides production facilities with information that is valuable for the developing and implementation of their SPCC Plans. This guidance does not address all aspects of the SPCC rule or options available for compliance, nor is it a substitute for the regulation itself.

D. BIA Regulations (25 CFR Part 226)

25 CFR 226.22 governing gas and oil operations in Osage County, also requires that operators shall at all times conduct their operations in a manner that will prevent pollution and the migration of gas, oil, salt water or other substances from one stratum into another, including any fresh water bearing formation. This section of the regulations also specifies requirements for pits used for drilling in order to protect water quality. See Appendix B for sample "Report of Completed or Deepened Wells.

GROUND WATER QUALITY PROTECTION

A. The Safe Drinking Water Act

The Safe Drinking Water Act (SDWA) requires EPA to develop minimum federal requirements for Underground Injection Control (UIC) programs and other safeguards to protect public health by preventing injection wells from contaminating underground sources of drinking water (USDWs).

What is an injection well and how are they used?

Injection operations in Osage County, Oklahoma, are primarily for the purpose of enhancing the recovery of oil from the numerous reservoirs that underlay the county. Fluids are injected into oil bearing formations to increase the formation pressure which in turn affects the production well productivity. Injection is also used for the disposal of excess produced water into a number of non-productive zones.

Who regulates injection wells in Osage county?

EPA Region 6 is charged with the direct implementation, in Osage County, of the mandates of the Safe Drinking Water Act (SWDA) through the Underground Injection Control (UIC) program. Regulations governing permitting and enforcement for the UIC program on the Osage Mineral Reserve are found at 40 CFR 147 Subpart GGG.

A team of engineers in the Ground Water/UIC Section is responsible for preparing the permits required to legally conduct those underground injection operations. The team also reviews the performance of wells that are authorized by rule to inject.

What regulatory controls are placed on injection wells?

The location of any wells in Osage County are subject to BIA requirements in 25 CFR Section 226.33.

Underground injection is allowed only if it is:

(1) Authorized by Rule or,
(2) Permitted under the UIC program.

No underground injection may result in the movement of contaminants into a USDW. Details of these rules can be found in Section 2903, Part 147 of Title 40 of the US Code of Federal Regulations (40 CFR §147.2903). Also see Figure 1 at the end of this section for an outline of the permitting process.

How do I obtain an application for a permit to operate an injection well?

EPA required permits:

You can obtain an EPA permit application package for an injection well from the Osage Nation Environmental and Natural Resources Department.

You may also contact the EPA Region 6 Injection permitting program with the Ground Water/UIC Section.. The website is:

http://www.epa.gov/region6/water/swp/uic/index.htm

You may also contact EPA Region 6. Listed below are EPA Region 6 officials responsible for permitting matters concerning the Osage UIC program in Region 6:

Director, Water Quality Protection Division	214-665-7101
Chief, Source Water Protection Branch	214-665-7150
Chief, Groundwater/UIC Section	214-665-8324
Chief, Administrative Support Office	214-665-7191

BIA required permits:

A BIA-issued permit to drill a well or convert an oil and gas well to an injection well is also required. Contact Osage Agency Subsurface Minerals at 918-287-5770 for more information or to request the required permit application forms.

What type of information is included in the EPA UIC permit application?

The permit application package provides the operator an opportunity to educate the permits engineer on the details of an injection project. The operator may post the data on several pre-formatted package documents that make up the application. The information is to assist the engineer in characterizing the injection system and in defining the variables that will set the operating conditions in the study area. An assessment of the risk of contamination under these operating conditions over a twenty year period will then be completed.

The following documents make up the application package for an Osage UIC permit:

Osage Agency forms 139 (see Form 1) and 208 (see Form 2);
The Well Schematic Form;
The Well Operation and Geologic Data Form;
The Well Tabulation;
Map(s).

What is the process once an EPA permit application is submitted?

The application will first be reviewed for completeness. If additional information is required you will be contacted. Once it is determined the application is complete it will be submitted for an engineering review.

What is evaluated during EPA's engineering review process?

The main objective of the engineering review process is to determine the rate of accumulation that is environmentally safe and to formulate operating conditions that will minimize the risk contamination risk to the Underground Source of Drinking Water (USDW).

Elements reviewed include:

- The rate of accumulation
- The reservoir flow system
- Identifying Points with Endangerment Potential
- Estimating the base of the USDW
- Estimating the reservoir pressure
- Estimating Formation Absolute Permeability, Porosity and Effective Thickness
- Estimating the water viscosity
- Estimating the Zone Of Endangering Influence (ZEI)
- Estimating the Maximum Allowable Injection Pressure

A more detailed discussion of these elements may be found in Appendix C of this document.

When the engineering review is complete what is the process for issuing a permit?

EPA uses an established administrative process to document and communicate the permit engineer's conclusions and recommendations for review, approval, and release to the permittee and the public. The permits engineer prepares a draft permit package consisting of a transmittal letter, a draft permit, a statement of basis, and a summary of information to appear in a newspaper notice. The Source Water Protection Branch Associate Director approves the draft permit package by signing the transmittal letter. Figure 1 is a flowchart to assist in visualizing the document preparation and submittal process.

Are there public participation requirements for issuing EPA UIC permits?

Yes, the permit writer will develop a summary statement of intent to issue an injection permit which will be published in a newspaper notice. The notice will be published in a newspaper of general circulation in the well permit area. The permittee and the public have fifteen (15) days following publication of the newspaper notice to offer comments on the draft permit.

What happens after the fifteen day comment period ends?

If neither the public nor the permit applicant submit written comments the Water Quality Protection Division Director issues the permit, and the permit becomes effective on the date issued.

If either the public or the permit applicants comment on the draft permit, the permit engineer prepares a response to comments and appropriate revisions to the draft permit, if any. The Water Quality Protection Division Director signs the permit. EPA then sends a copy of the final permit to the permit applicant and anybody who commented on the draft permit. The permit becomes effective 30 days after Division Director approval.

When can the operator begin using the injection well?

Final permits require the permittee to obtain authorization to inject before using the well for injection. The permittee must comply with listed conditions (most notably completing required construction and passing a mechanical integrity test (MIT)) before receiving such authorization. The Chief of the Groundwater/UIC Section may give verbal authorization to inject. The Water Quality Protection

Division Director later issues a written authorization to inject.

Can a permit be modified after it is issued?

A current UIC permit may be modified under one of three different scenarios:

a) **Operator initiated request** - An operator can submit a written request for a permit modification whenever a reasonable cause exists. The circumstances under which an operator may obtain a permit modification are provided in 40 CFR §147.2927.

b) **Interested Party Requested** - Any interested party may submit to the Regional Administrator a written request for the modification of an Osage UIC permit. The Regional Administrator may grant the request if reasonable cause for modification exists (40 CFR §147.2927 (a) (5)).

b) **EPA Initiated Modifications -** The Regional Administrator may modify any permit If it receives information during the course of a permit review or inspection that warrants a permit modification (40 CFR §147.2927(a) (2)).

What types of construction controls and requirements are included in the final EPA UIC Permit?

Construction Requirements include documenting casing and cement, types of wellhead fitting, tubing and packer requirements and plugging requirements if the injection well is taken out of service.

Are there operational requirements included in permit conditions?

In addition to the construction requirements the permit implements specific requirements to assure that the injection well continues to operate as designed. Such requirements include mechanical Integrity testing, establishing maximum wellhead injection pressures, restricting the injected fluid type and fluid level monitoring. Osage UIC program regulations require injection well operators to complete a MIT at least every five years.

The Regional Administrator can require a different testing frequency on a case-by-case basis (40 CFR §§147.2920(b) (1) (v) and 147.2920(b) (2)(v)). This allows the prescription of testing frequencies that reflect the risk of mechanical failure in wells, especially in the case of less conventional completions. For example, the MIT frequency for wells without cemented surface casing through USDWs is usually three years.

How does EPA know that permit conditions are being implemented and followed?

In addition to the permit conditions listed above the permits include a condition on reporting. A key reporting requirement is the annual operation report. This report is required for all injection wells. Injection well operators must submit an annual report of injection activities to the Environmental Protection Agency.

EPA sends a notice and a suggested report form (see Form 3) to injection well operators when the report is due. The report due date depends on where the well is located. The following shows report due dates by well location:

Township/Range Location	Report Due Date
Townships 20 North - 23 North, Ranges 6 East - 12 East	January 31
Townships 27 North - 29 North, Ranges 5 East - 12 East	April 30
Townships 24 North - 26 North, Ranges 2 East - 7 East	July 31
Townships 24 North - 26 North, Ranges 8 East - 12 East	October 31

What information must be included in the annual report?

Annual reports must include the following:

- Average and maximum monthly injection pressures.
- Total barrels of fluid injected each month.
- Average and maximum annulus pressure (required only if the operator is using annulus monitoring to demonstrate mechanical integrity or the permit requires annulus monitoring).

See sample Annual Report as Appendix D.

What other types of information are required to be reported?

Common requirements are for the operators to report are oil and water production from nearby wells, and fluid levels in the injection well or nearby wells.

(The operator should review the UIC permit for specific requirements.) Each permittee must submit this information to the EPA annually. Inactive wells may require fluid level monitoring information. A special report form will be provided to include fluid level monitoring information.

The operator must keep actual records of monitoring (pumper's log, actual charts, etc.) and a copy of the submitted report for three years after completing the report.

What happens when an injection well is no longer operated?

The operator must plug its injection wells within one year after ceasing injection operations. EPA may extend plugging deadline for injection wells if there is a viable plan for future use and no fluid movement into an underground source of drinking water would occur. BIA regulations require that an application for permit to plug be obtained prior to plugging and the BIA witnesses the well plugging.

May an injection well be converted for production use?

An operator may convert any injection well to production use at any time. When conversion is complete and the EPA removes the well from its injection well inventory, jurisdiction for the well reverts to the BIA.

- Obtain conversion permit from the BIA.
- Complete physical conversion of well (i.e., install rods and tubing, pump jack and motor and begin production).
- Submit Osage Agency Form No. 139 to both the BIA and the EPA UIC office showing that the conversion is complete.

How does EPA assure that the well has been converted?

The well operator must demonstrate that conversion has actually been completed. If a well is swabbed for production, the operator must (in addition to the items listed above) notify the EPA by letter of the production method and submit a copy of the first lease status report after conversion to verify the amount of oil being produced.

If the well is authorized by permit, the permit remains in effect until the permittee requests in writing that the permit be terminated. As long as the permit is in effect, the well can be converted back to injection at any time. Before actual injection takes place, the operator must demonstrate that the well has mechanical integrity.[1]

The EPA notifies the well operator before amending its records to show that a well has been converted to production. If the well is being tested for production and may be converted back to injection within a short time (e.g., one month), the operator should notify the EPA upon receipt of the notice of permit termination or loss of authorization by rule.[1]

Can a lease be transferred and if so what are the procedures?

Before buying or accepting an assignment of a lease, the prospective lessee should check with the BIA and EPA to verify that the lease is compliant with BIA and EPA requirements.[3] The prospective lessee should obtain all pertinent records of well construction and operation from the seller as part of their agreement.[3]

After completing the transfer, the new lessee must submit a signed lease assignment (BIA Form F) and a copy of its bond or other form of financial assurance to the BIA.[2] The seller should submit an operation report to the EPA for the portion of the report period that it operated the well.

The assignment form shows the effective date of the transfer. The seller is responsible for all reporting, monitoring, and violations of program requirements until the effective date of the transfer. The buyer is responsible for the lease after the effective date of the transfer.

If the injection well is authorized by rule, the buyer should notify the EPA of the lease transfer. The notice may be a copy of the lease assignment and bond sent to the BIA.[3]

If the well is authorized by permit, the seller must notify the EPA of the proposed lease transfer at least ten days before the proposed transfer date. The notice must include a specific date for the transfer and proof that the transferee has financial responsibility for the well. The transfer is effective on the date of the transfer, if the seller submits required documentation and the EPA does not respond with a notice that the permit will be modified[1].

The notice of lease transfer may be a copy of the lease assignment and the bond

1Requirementof Environmental Protection Agency.
[2] Requirement of Bureau of Indian Affairs regulation or policy
[3] Recommended management practice.

or other form of financial assurance sent to the BIA.

How do I demonstrate that the well is operationally sufficient?

All wells must have mechanical integrity before being used for fluid injection.[1] The operator must notify the Osage Nation Environmental and Natural Resources Department at least five days before testing a well so their representative can witness the test.[1] Either a Tribal or EPA inspector must witness all mechanical integrity tests.

What is the purpose of a mechanical integrity test?

The two parts of the mechanical integrity demonstration are to prove that:[1] There is no significant fluid movement of fluids through vertical channels behind the well casing and there are no significant leaks in the casing, tubing, or packer.

How are mechanical integrity tests performed?

Table 2 summarizes the types of tests and requirements to comply with this requirement. The inspector measures the fluid return at the conclusion of each mechanical integrity annulus pressure test.[1] This is used by the test reviewer to estimate packer depth. If fluid returns indicate shallow packer depth, the EPA Engineer may require proof of packer setting depth before verifying well integrity. Verification may include providing a tubing tally, a tubing log or pulling tubing from the hole

The EPA has approved the mechanical integrity testing procedures shown below for injection wells authorized by rule.

(1) Demonstrate mechanical integrity of the tubing and packer;
(2) Install and maintain a monitoring system approved by EPA which would detect and warn of fluid level in casing/tubing annulus within 100 feet of the base of the lowest underground source of drinking water (USDW);
(3) Measure the static fluid level in the well annulus at least annually;
(4) If the fluid level is detected within 100 feet of the USDW:

What do I do if my annulus fluid level is detected within 100 feet of the USDW?

(a) Notify the EPA within 48 hours; and,

(b) Reset the monitoring device to detect the fluid level within 75 feet of the base of USDWs within five (5) days.

If the fluid level rises to within 75 feet of the USDW:

(a) Report to the EPA within 48 hours (The report must include the rate of fluid level rise in feet per day;
(c) Reset the monitoring device to detect fluid within 50 feet of the base of USDWs within five days

If fluid rises to within 50 feet of the base of USDWs,

(a) Immediately shut in the well and report to the EPA;
(d) Submit a corrective action plan to the EPA if the fluid level remains less than 50 feet below the base of USDWs.

What if I fail my mechanical integrity test?

You must cease using the well for fluid injection until you can demonstrate that the well has achieved mechanical integrity. Any repair that allows a satisfactory mechanical integrity demonstration is allowed. (NOTE: The use of Angaard or other materials that prevent testing the full length of casing is prohibited). Common repair options include:

(1) Cement squeeze;
(5) Install a concentric packer;
(6) Install a liner;
(7) Repair or Replace the packer;
(8) Cement the casing from the surface to the hole;
(9) Place a casing patch;
(10) Replace the corroded casing joint;
(11) Replace joint of tubing with hole;
(12) Set a liner on a packer (This option requires special monitoring and testing. Operator should call EPA Groundwater/UIC Section for specifics.

Can an alternative mechanical integrity test be used?

EPA regulations allow the EPA Regional Administrator to approve alternative mechanical integrity testing procedures applicable to injection wells authorized by rule. EPA Headquarters must approve alternative test procedures for wells authorized by permit.

What if I wish to plug my injection well?

To get authority to plug a well follow the following steps:

- Submit BIA form No. 139 to the Bureau of Indian Affairs (Osage Agency) and, if plugging an injection well, to the Osage Nation Environmental and Natural Resources Department at least five days before planning to plug a well.
- Include an outline of plugging procedures or request plugging instructions from the appropriate agency.
- Include a $15.00 filing fee with the plugging plan submitted to the BIA.
- Table 3 and Figures 2 through 8 summarize plugging requirements for several types of well construction.

After you receive notification from EPA that your plugging plan is approved, you must contact the EPA at 918-605-1643 at least five days before initiating plugging so they can witness plugging procedures.

Are there any additional requirements once I plug the well?

After you have plugged the well you must:

- Cut off the casings and restore the surface location, including removing all junk from the location.

- You must also submit a BIA form No. 139 which includes a summary of actual plugging procedures and copies of cement tickets to the BIA and, if the well is an injection well, to the Osage Nation Environmental and Natural Resources Department, and

- Request an inspection from the BIA and, if the well is an injection well, the Osage Nation Environmental and Natural Resources Department.

NOTE: ONLY THE BIA MUST BE NOTIFIED IF PLUGGING A PRODUCTION WELL.

Table 1: Well Construction Requirements

Date Well Drilled	Casing and Cementing Requirements
Pre-April 1953	1. Cemented casing through all underground sources of drinking water OR 2. Cemented casing 100 feet above the injection formation
April 1953 - December 1984	1. Cemented casing through water with less than 3000 mg/1 total dissolved solids. 2. Cemented casing 100 feet above injection formation
After December 1984	1. Cemented casing at least 50 feet below water with less than 10,000 mg/1 total dissolved solids. 2. Cemented casing 100 feet above the injection zone

Table 2
Casing, Tubing, and Packer Mechanical Integrity Test Requirements

Test Options	Procedures	Comments
Casing/Tubing Annulus Pressure Pressure Test	1. Apply pressure of 200 psi to annulus provided that: a) Annulus pressure must be at least 100 psi different from tubing pressure; and/or b) Annulus pressure may be less than 200 psi if required to achieve the 100 psi differential, but can not be less than 100 psi. 2. Observe pressure for 30 minutes. 3. Release pressure and measure fluid returned.	1. Packer fluid must be liquid. 2. Inspector must verify current packer depth with operator. 3. Collect and measure fluid returns at the end of the test. 4. Pass if packer depth is compliant with permit conditions, calculations verify packer depth, and pressure loss after 30 minutes is less than 10%.
Ada	1. Measure the static fluid level in the well. 2. Calculate required test pressure. 3. Apply gas (usually nitrogen) pressure to force fluid into the perforations. Observe pressure for 30 minutes.	1. Can be used to: a) Test wells with no tubing and packer. b) Test tubing and packer in wells with perforations or known casing leaks above the packer. c). Determine the depth of the top casing or tubing leak. 2. Pass test if pressure stays within the predicted range for 30 minutes
Continuous Positive Annulus Pressure (e.g., "Barrel Test")	1. Fill the casing/tubing annulus with liquid and continuously maintain a positive pressure. 2. Observe and record the pressure at least monthly. 3. Report annulus pressure to	1. Cannot use if the well previously failed an annulus pressure test. 2. Many operators comply by monitoring the fluid level in a barrel connected to the annulus. or 3. Fail test if annulus pressure drops to

	the EPA on the annual operation report Including monthly volumes of fluid added to or removed from the annulus.	0 psig, the operator must frequently add or remove fluid from the annulus to maintain stable pressure, or the operator fails to report monitoring results on its annual report.
Continuous Annulus Fluid Level Monitoring (e.g., "Osage Sentry")	Discuss with EPA Engineer	1. Install a device in the well annulus which would immediately signal when the fluid level rises to the monitor location. 2. May be used for wells with tubing and packer integrity but casing leaks. 3. Must measure annulus fluid level annually. 4. Must demonstrate tubing and packer integrity every five years.
Radioactive Tracer Test	Discuss with EPA Engineer	

Table 3
Plugging Requirements

<table>
<tr><th>Current Well Construction</th><th>Pulled Casings</th><th>Plugging Procedure</th></tr>
<tr><td rowspan="2">Surface casing set and cemented at least 50 feet below all USDWs or production casing cemented to surface,
AND

Production casing cemented above production formation.

See Figures 2, 6 and 7</td><td>Production casing pulled 50 feet below the base of USDWs</td><td>a. Set plug through injection formation to 50 feet above formation.
b. Pull production casing from at least 50 feet below base of USDWs.
c. Set plug from 50 feet below to 50 feet above surface casing shoe.
d. Set plug from 20 to 3 feet subsurface.
e. Cut off the casing 3 feet subsurface, weld on a cap and restore location.</td></tr>
<tr><td>Production casing NOT pulled 50 feet below the base of USDWs</td><td>a. Set plug through injection formation to 50 feet above formation.
b. Part or perforate production casing at least 50 feet below base of USDWs and circulate cement to surface. (Not applicable if production casing is cemented to surface)
c. Set plug from 50 feet below to 50 feet above the base of USDWs.
d. Set plug from 20 feet to 3 feet subsurface.
e. Cut off casings 3 feet subsurface, weld on cap, and restore location.</td></tr>
<tr><td>Surface casing not cemented through all USDWs;

AND

Production casing cemented above injection formation</td><td>Production casing pulled at least 50 feet below base of USDWs</td><td>a. Set plug through injection formation to 50 feet above formation.
b. Pull production casing at least 50 feet below base of USDWs.
c. Set plug from 50 feet below base of USDWs to 50 feet above surface casing shoe.
d. Set plug from 20 feet to 3 feet subsurface.
e. Cut off casings 3 feet subsurface, weld on cap, and restore location.</td></tr>
</table>

See Figures 3, 4, 6 and 7	Production Casing not pulled	a. Set plug through injection formation to 50 feet above formation. b. Perforate or part production casing at least 50 feet below base of USDWs and circulate cement behind casing. c. Set plug from 50 feet below to 50 feet above the base of USDWs. d. Set plug from 20 feet to 3 feet subsurface. e. Cut off casings 3 feet subsurface, weld on cap, and restore location.

Figure 1

US EPA Region 6 Osage UIC Program

Plugging and Abandonment Requirements for Wells in OIL and Gas Operations
Surface casing Plugs (40 CFR 147.2905.(e).(1) and
(40 CFR 147.2905.(e).(3)

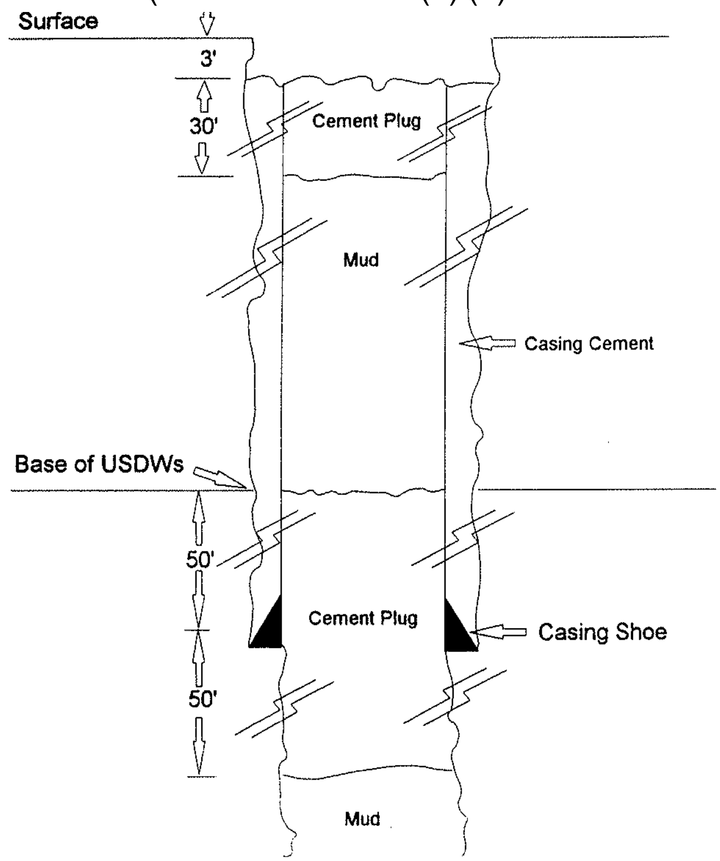


Figure 2

US EPA Region 6 Osage UIC Program

Plugging and Abandonment Requirements for Wells in Oil and Gas Operations
Surface casing Plugs (40 CFR 147.2905.(e).(1) and
(40 CFR 147.2905(e)(3)

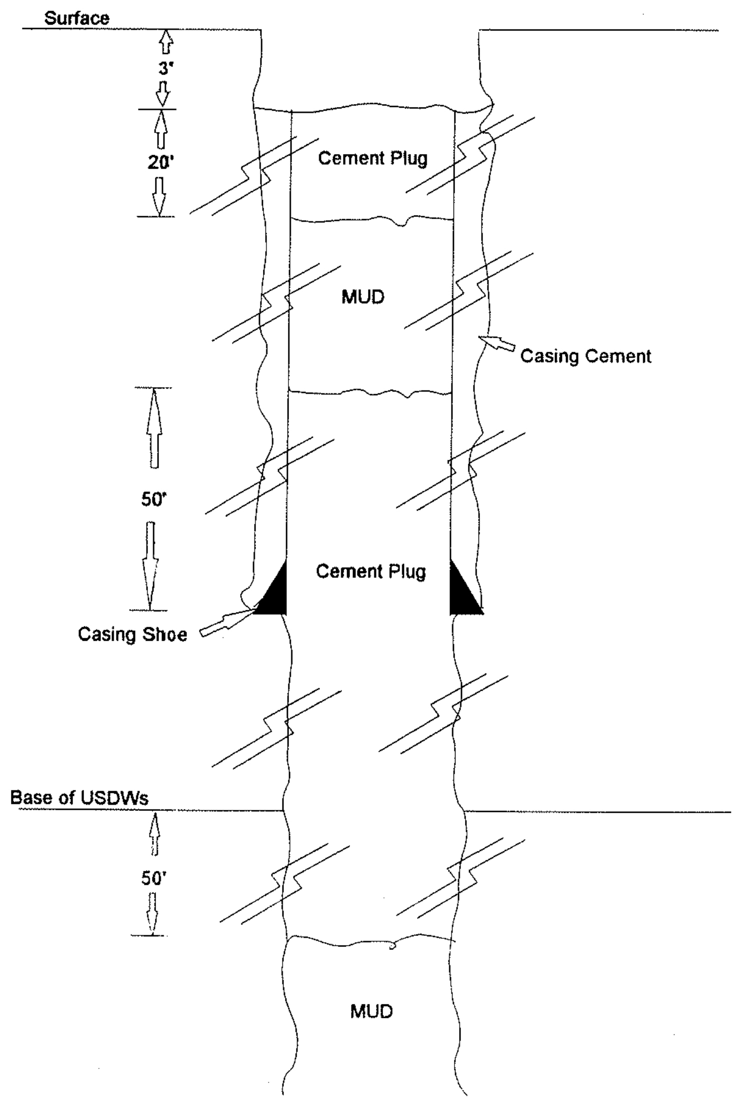


Figure 3
US EPA Region 6 Osage UIC Program

Plugging and Abandonment Requirements for Wells in Oil and Gas Operations
For Open Hole Section (Below Production Casing Shoe) (40 CFR 147.2905.(g))

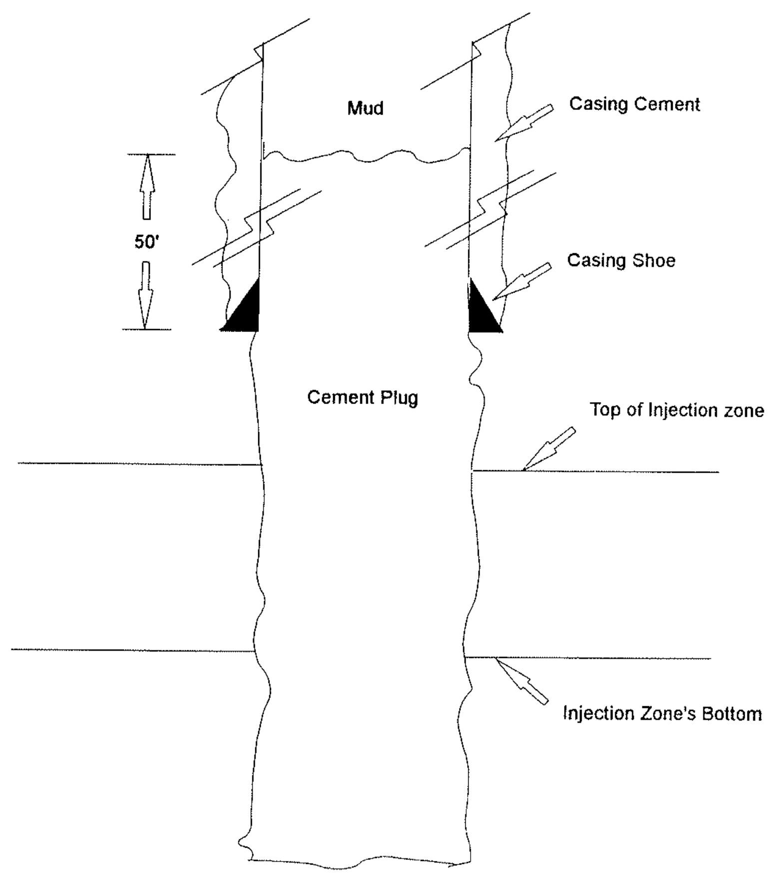


Figure 4
US EPA Region 6 Osage UIC Program

Plugging and Abandonment Requirements for Wells in Oil and Gas Operations
Plugs For Hole Section With Liner or Screen (40 CFR 147.2905.(g))

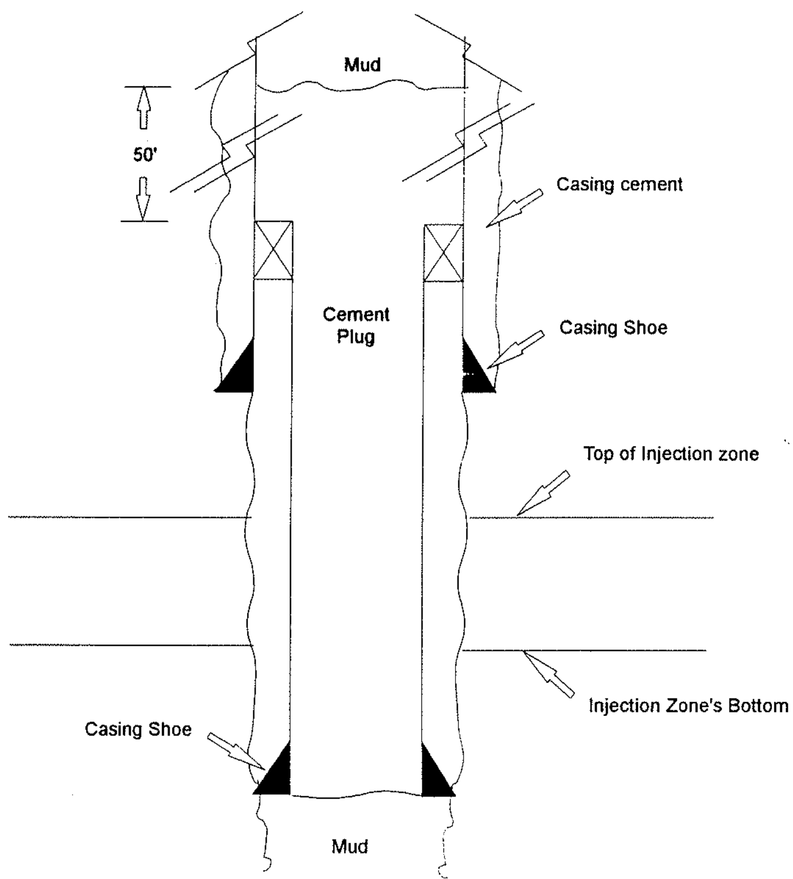


Figure 5
US EPA Region 6 Osage UIC Program

Plugging and Abandonment Requirements for Wells in Oil and Gas Operations
Plug For Open Hole Section Below Production Casing Shoe
(40 CFR 147.2905.(g)

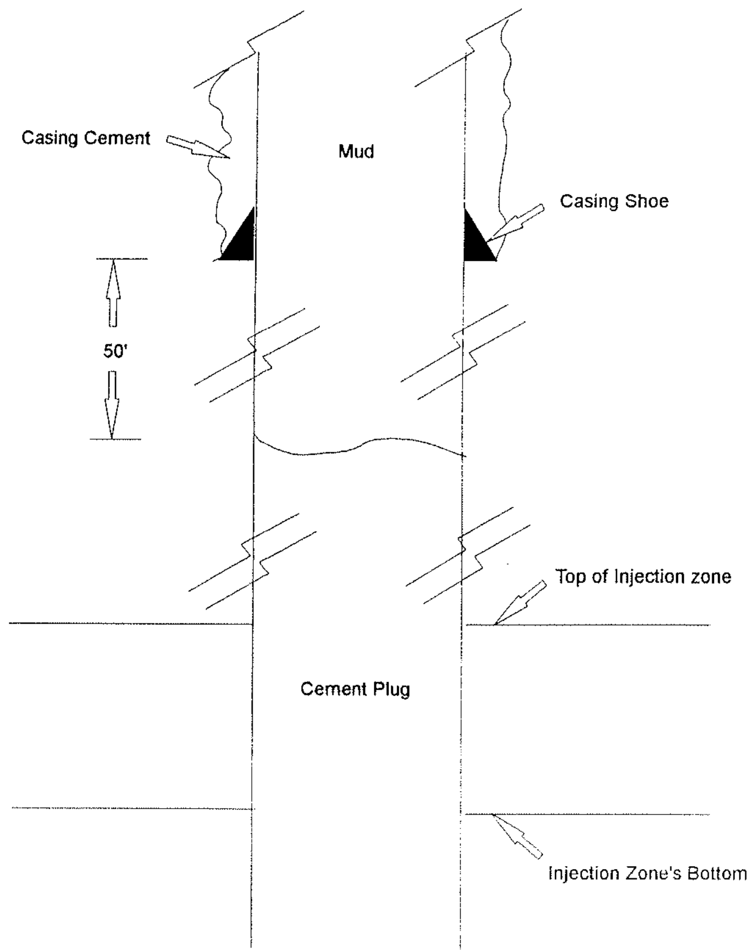


Figure 6

US EPA Region 6 Osage UIC Program

Plugging and Abandonment Requirements for Wells in Oil and Gas Operations
Plugs For Ripped Production casing (Cemented)
(40 CFR 147.2905.(f).(2)

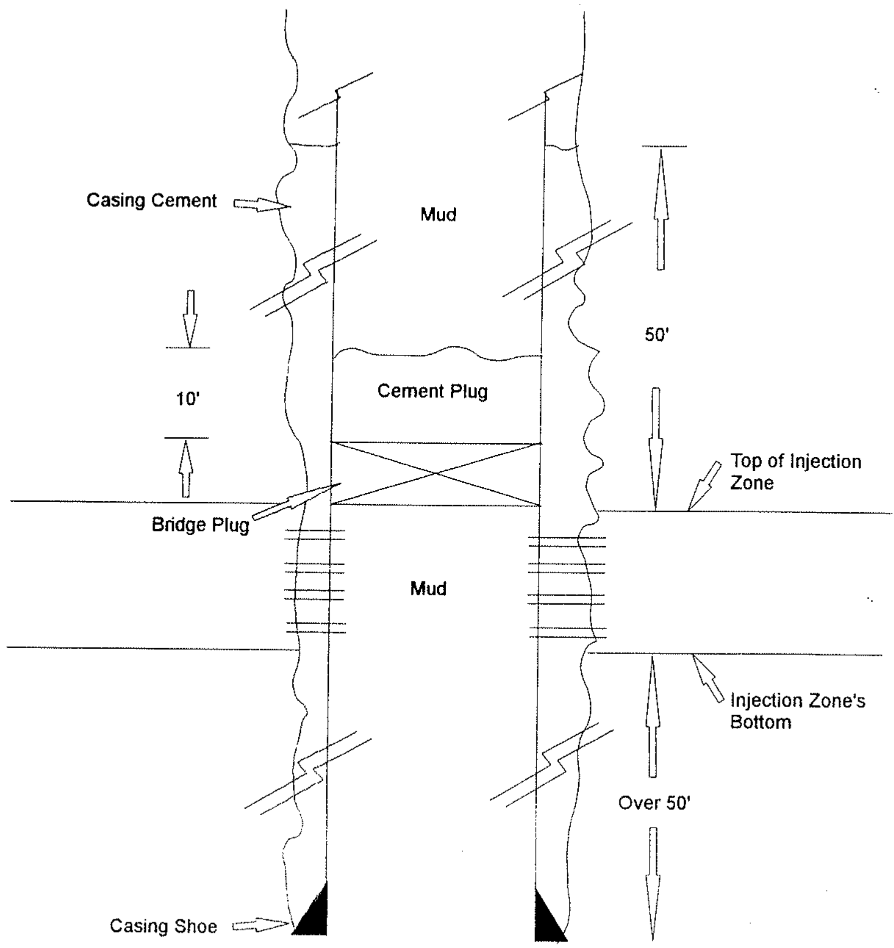
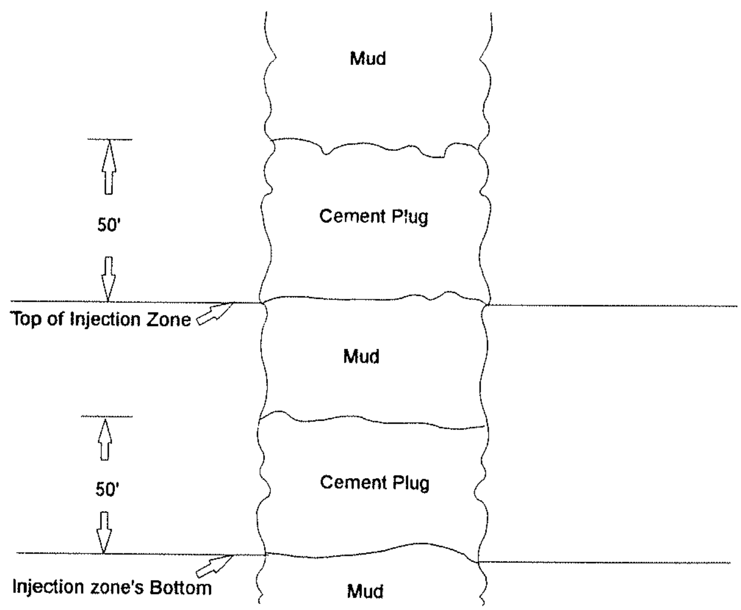


Figure 7

US EPA Region 6 Osage UIC Program

Plugging and Abandonment Requirements for Wells in Oil and Gas Operations
Open Hole Section Plugs (40 CFR 147.2905.(f).(1)



AIR POLLUTION PREVENTION

II. AIR POLLUTION PREVENTION

A. The Clean Air Act

What is the Clean Air Act?

The Clean Air Act (CAA) is a federal law covering the entire U.S. EPA has significant responsibilities under the CAA. EPA sets limits on certain air pollutants, including setting limits on how much can be in the air anywhere in the United States. This helps ensure basic health and environmental protection from air pollution for all Americans. The Clean Air Act also gives EPA the authority to limit emissions of air pollutants coming from sources like chemical plants, utilities, and steel mills.

States, tribes and local governments may also have delegated responsibilities under the Act's requirements. For example, representatives from state, tribal and/or local agencies work with companies to reduce air pollution (known as pollution prevention). They also review and approve permit applications for industries or chemical processes. Individual states or tribes may also set stronger or more stringent air pollution laws, but they may not have weaker pollution limits than those set by EPA. EPA must approve state, tribal, and local agency plans for reducing air pollution.

What is the Osage Nation's role in air pollution and prevention in Osage County?

In its 1990 revision of the Clean Air Act, Congress recognized that Indian Tribes have the authority to implement air pollution control programs. EPA's Tribal Authority Rule gives Tribes the ability to develop air quality management programs, write rules to reduce air pollution and implement and enforce their rules in Indian Country. While state and local agencies are responsible for all Clean Air Act requirements, Tribes may choose to develop and implement only those parts of the Clean Air Act that they deem to be appropriate.

The Osage Nation has an Environment and Natural Resources Department with staff who may obtain EPA-approved inspectors credentials for specific environmental programs. The Department conducts environmental monitoring, sampling and other activities, and coordinates with EPA and other federal agencies on matters of common interest.

Do I need an air permit to operate a gas and oil production well in Osage County?

A new well site or an existing well site could require one or more air permits after all emission sources and points are calculated. All emission estimation methods used for permitting should also be used in a way that is consistent with protocols established in federal regulations.

What general best management practices should I use to reduce or prevent air pollution?

Best management practices (BMPs) are designed to prevent or reduce impacts on ambient air from oil and gas operations.

In general terms, all facilities which have the potential to emit air contaminants should be maintained in good working order and operated properly during facility operations. Each operator should establish and maintain a program to replace, repair, and/or maintain facilities to keep them in good working order. The minimum expectations of such a program should include:

1. Compliance with manufacturer's specifications and recommended programs applicable to equipment performance and effect on emissions, or alternatively, an owner or operator developed maintenance plan for such equipment that is consistent with good air pollution control practices which includes the cleaning and routine inspection of all equipment; and

2. Replacement and repair of equipment on schedules which prevent equipment failures and maintain performance; and

3. "Green Completion" practices and procedures to reduce methane emissions, air toxics, flaring events, and noise levels; and

4. Conduct daily audio, visual and olfactory inspections recorded in a log book.

What best management practices should I use to prevent or reduce fugitive air emissions?

Fugitive air emissions are those not released through a stack, vent or other confined air stream. Such emissions can escape from equipment leaks or evaporation. The following should be applied to all fugitive components associated with the well site:

1. Install, check, and properly maintain all seals and gaskets in volatile organic compounds (VOC) or H2S service to prevent leaking. Physically inspect all components weekly for leaks, and may be subject to a leak detection and repair (LDAR) program.

2. Repair all components found to be leaking. Make every reasonable effort to repair a leaking component. Immediately tag or note in a log all leaks not repaired.

3. Repair leaks as quickly as possible at manned and unmanned sites.

4. Close (but do not completely seal to maintain safe design functionality) tank hatches, not designed to be completely sealed, except for sampling, gauging, loading, unloading, or planned maintenance activities.

5. Locate new and reworked valves and piping connections in a place that is reasonably accessible for leak checking to the extent that good engineering practices will permit.

6. Capture all non-combustion VOC emissions and direct them to an appropriate control device with a minimum design control efficiency of at least 95%.

7. Use optical leak imaging using a hand-held infrared camera to quickly locate leaking components for rapid repair or replacement.

8. Use dust control measures (spraying of water) to control dust, if necessary. Water used for dust abatement should not contain oil or solvents. Do not use dust abatement as a means of water disposal.

9. Install and properly use vapor recovery units (VRU) to reduce methane emissions.

10. Convert gas pneumatic controls to instrument air to eliminate methane emissions.

What best management practices should I deploy in flaring to minimize air pollution?

Flares used for control of emissions from production, planned Maintenance Startup Shutdown (MSS), emergency, or upset events should maintain a destruction efficiency of 98% for VOCs and H2S, and 99% for VOCs. All flares should adhere to manufacturers' operation and maintenance requirements to minimize emissions in accordance with the following.

1. Meet specifications for minimum heating values of waste gas, maximum tip velocity, and pilot flame monitoring found in 40 CFR §60.18;

2. If necessary to ensure adequate combustion, add sufficient gas to make the gases combustible;

3. An infrared monitor is considered equivalent to a thermocouple for flame monitoring purposes;

4. Use an automatic ignition system in lieu of a continuous pilot;

5. Light flares at all times when gas streams are present;

6. Use sweet gas or liquid petroleum gas fuel for all flares except where only field gas is available and it is not sweetened at the site;

7. Design and operate flares with no visible emissions, except for periods not to exceed at total of 5 minutes during any two consecutive hours.

8. Flares may be designed with steam or air assist to help reduce visible emissions from the flare but should meet the appropriate requirements in 40 CFR 60.18.

9. At no time should minimum heating values fall below the associated minimum heating value in 40 CFR §60.18, and

10. Collect and compress vented or flared gas and then sell it as a product.

What best management practices should I use to reduce or prevent emissions from tanks and ponds?

Do not allow open-topped tanks or ponds containing VOCs or H2S. Close tank hatches and valves, which emit to the atmosphere, except for sampling or planned maintenance activities. Design and operate all pressure relief devices (PRD) to ensure that proper pressure in the vessel is maintained. They should stay closed except in upset or malfunction conditions. If the PRD does not automatically reset, reset it as quickly as possible at a manned or unmanned site. Also, equip all storage tanks with a storage capacity greater than 500 gallons with a submerged fill.

It is also recommended that loading be performed with submerged filling, or vapor balancing back to the tank and any subsequent recovery or control device. The following should be undertaken.

Do not allow splash loading and uncontrolled vacuum truck loading. Perform loading with a control effectiveness of at least 42% as compared to splash loading. Loading may occur by submerged filling or equivalent prevention or recovery technique.

a) Capture loading vapors and direct them to an appropriate control device with a minimum design control efficiency of at least 98%, routed to a vapor recovery unit (VRU) with a control effectiveness of at least 95%, or vapor balanced back to the delivering storage tank equipped with a VRU, or connected to a control device with a minimum design control efficiency of at least 95%.

b) Where loading control is required, connect the collection or capture system to the tank truck so all displaced vapors are directed to the control device and the control device is operational before loading begins. When properly connected the capture efficiency should be assumed to be 70% efficient at capturing the displaced truck vapors. The capture efficiency may be assumed to be efficient when the tanker truck has certification that the tank has passed vapor-tightness testing. Discontinue loading when liquid or gas leaks from the loading or collection system are observed.

What is hydrogen sulfide and when is it immediately dangerous?

Hydrogen Sulfide, or H2S, is a flammable, colorless gas with an odor characteristic of rotten eggs. Hydrogen sulfide (H2S) may occur naturally in crude petroleum and natural gas production. It is not present in all cases but where drilling operations may penetrate certain zones.

The IDLH for H2S is 100 ppm. IDLH is an acronym for Immediately Dangerous to Life or Health, and is defined by the US National Institute for Occupational Safety and Health (NIOSH) as exposure to airborne contaminants that is "likely to cause death or immediate or delayed permanent adverse health effects or prevent escape from such an environment."

What are the best management practices I should deploy to prevent or reduce emissions from Hydrogen Sulfide?

1. Operations should ensure that personnel who will be working on the well site be properly trained in H2S drilling and contingency procedures in accordance with the general training requirements outlined in the American Petroleum Institute's Recommended Practice (RP) 49 for Safe Drilling of Wells containing H2S, Section 2.

2. During drilling operations, where H2S is reasonably expected to be present, maintain and implement a vigorous safety plan to include hydrogen sulfide (H2S) monitors onsite with alarms and sirens, appropriate signs, and the mandatory wearing of individual H2S monitors for personal safety and protection. H2S should not be released into the environment. Various guidance, such as BLM's On-Shore Order #6, provide details as to appropriate criteria for detection and monitoring equipment and signage.

3. Hydrogen sulfide is not designated as a hazardous air pollutant so EPA does not have a specific numerical criteria for its control (however, note the IDLH level above). H2S is a component of fugitive emissions that may be released from oil production facilities. EPA generally controls H2S through implementation of BMPs designed to control fugitive emissions.

4. Additional best management practices can be found at the U.S. EPA Energy Gas Star Website: **http://www.epa.gov/gasstar/tools/recommended.html**

WASTE MANAGEMENT AND ENVIRONMENTAL COMPLIANCE

WASTE MANAGEMENT AND ENVIRONMENTAL COMPLIANCE

A. The Resource Conservation and Recovery Act (RCRA)

What is the Resource Conservation and Recovery Act (RCRA)?

RCRA is a law that is intended to govern the management of waste materials, including those that may be toxic to humans and animals. Under Subtitle C regulations, RCRA has exempted certain wastes associated with the exploration and production of crude oil, natural gas, and geothermal resources. However, the exemption is limited in scope and does not cover all wastes generated in the oil field. The EPA recognizes that the oilfield produces large volumes of waste that are typically non-toxic or have a low toxicity value as normally regulated by RCRA. With this understanding, the EPA has exempted wastes that are "intrinsic and uniquely associated with oil and gas exploration."

What is "exempted" waste in general?

In general, the exempt status of an E&P waste depends on how the material was used or generated as waste, not necessarily whether the material is hazardous or toxic. For example, some exempt E&P wastes might be harmful to human health and the environment, and many non-exempt wastes might not be as harmful. The following simple rule of thumb can be used to determine if an E&P waste is exempt or non-exempt from RCRA Subtitle C regulations:

- Has the waste come from down-hole, i.e. was it brought to the surface during oil and gas E&P operations?
- Has the waste otherwise been generated by contact with the oil and gas production stream during the removal of produced water or other contaminants from the product?
- If the answer to either question is yes, then the waste is likely considered exempt from RCRA Subtitle C regulations. It is important to remember that all E&P wastes require proper management to ensure protection of human health and the environment.

What are specific, listed "exempted" wastes?

In its 1988 regulatory determination, EPA published the following lists of wastes that were determined to be exempt. These lists are provided as examples of wastes regarded as exempt and should not be considered to be comprehensive. The exempt waste list applies only to those wastes generated by E&P operations. Similar wastes generated by activities other than E&P operations are not covered by the exemption.

- **A.** Produced Water
- **B.** Drilling fluids
- **C.** Drill cuttings
- **B.** Rigwash
- **C.** Drilling fluids and cuttings from offshore operations disposed onshore
- **D.** Geothermal production fluids
- **E.** Hydrogen sulfide abatement wastes from geothermal energy production
- **F.** Well completion, treatment and stimulation fluids
- **G.** Basic sediment, water, and other tank bottoms from storage facilities that hold product and exempt waste
- **H.** Accumulated materials such as hydrocarbons, solids, sands and emulsion from production separators, fluid treating vessels, and production impoundments
- **I.** Pit sludges and contaminated bottoms from storage or disposal of exempt wastes
- **J.** Gas plant dehydration wastes, including glycol-based com- pounds, glycol filters, and filter media, backwash, and molecular sieves
- **K.** Workover Wastes
- **L.** Cooling tower blowdown
- **M.** Gas plant sweetening wastes for sulfur removal, including amines, amine filters, amine filter media, backwash, precipitated amine sludge, iron sponge, and hydrogen sulfide scrubber liquid and sludge
- **N.** Spent filters, filter media, and backwash (assuming the filter itself is not hazardous and the residue in it is from an exempt waste stream)
- **O.** Pipe scale, hydrocarbon solids, hydrates, and other deposits removed from piping and equipment prior to transportation
- **P.** Produced sand
- **Q.** Packing fluids
- **R.** Hydrocarbon-bearing soil
- **S.** Pigging wastes from gathering lines
- **T.** Wastes from subsurface gas storage and retrieval, except for the non-exempt wastes listed below.
- **U.** Constituents removed from produced water before it is injected or otherwise disposed of
- **V.** Liquid hydrocarbons removed from the production stream but not from oil refining
- **W.** Gases from the production stream, such as hydrogen sulfide and carbon

dioxide, and volatilized hydrocarbons

X. Materials ejected from a producing well during blowdown

Y. Waste crude oil from primary field operations

Z. Light organics volatilized from exempt wastes in reserve pits, impoundments, or production equipment

What are specific, listed "non-exempted" wastes?

In its 1988 regulatory determination, EPA published the following lists of wastes that were determined to be non-exempt. These lists are provided as examples of wastes regarded as non-exempt and should not be considered to be comprehensive.

A. Unused fracturing fluids or acids

B. Gas plant cooling tower cleaning wastes

C. Painting wastes

D. Waste solvents

E. Oil and gas service company wastes such as empty drums, drum rinsate, sandblast media, painting wastes, spent solvents, spilled chemicals, and waste acids

F. Vacuum truck and drum rinsate from trucks and drums transporting or containing non-exempt waste

G. Refinery wastes

H. Liquid and solid wastes generated by crude oil and tank bottom reclaimers[4]

I. Used equipment lubricating oils

J. Waste compressor oils, filters, and blowdown

K. Used hydraulic fluids

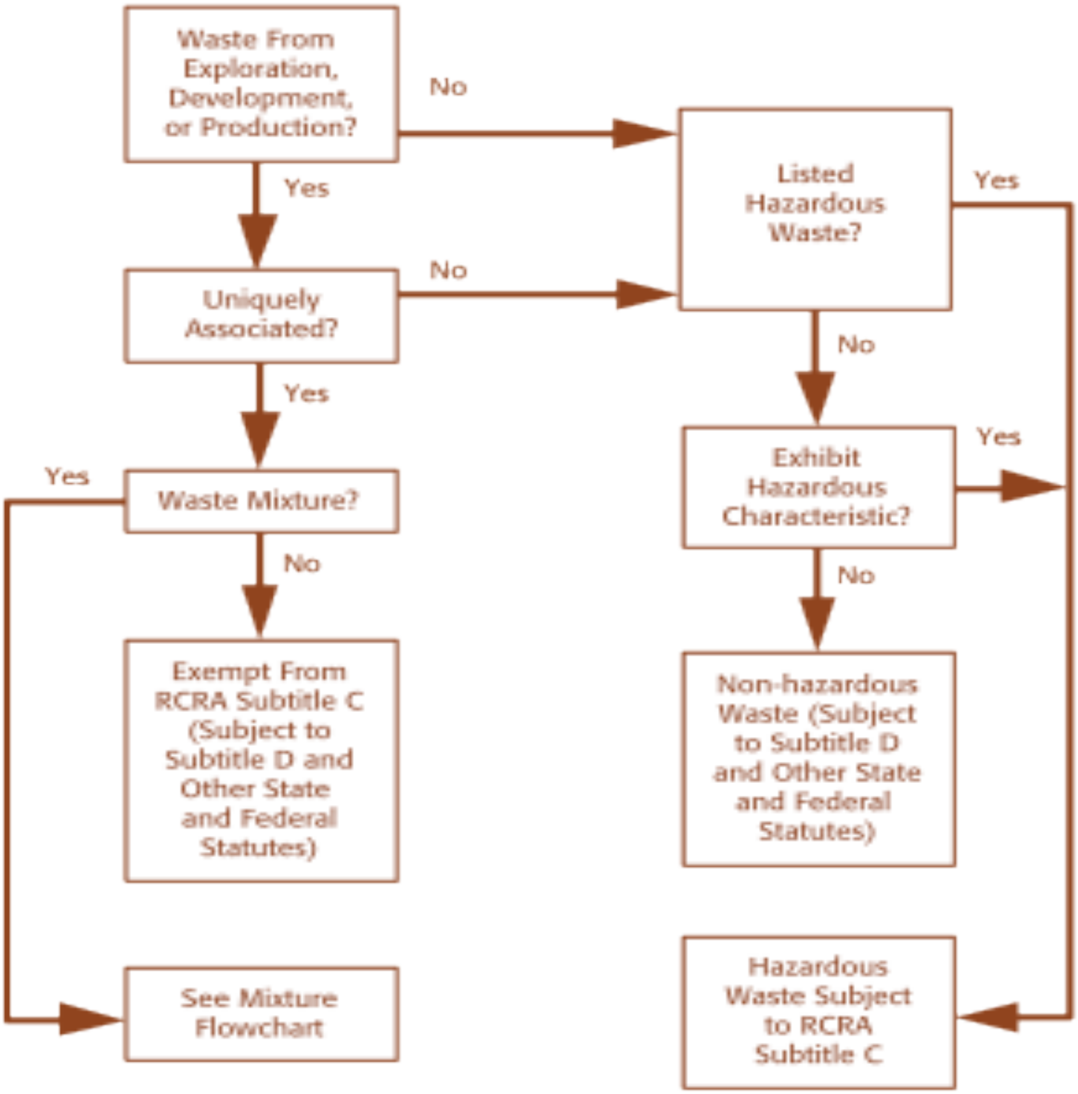
L. Waste in transportation pipeline related pits

M. Caustic or acid cleaners

N. Boiler cleaning wastes

[4] Although non-E&P wastes generated from crude oil and tank bottom reclamation operations (e.g., waste equipment cleaning solvent) are non-exempt, residuals derived from exempt wastes (e.g., produced water separated from tank bottoms) are exempt. For a further discussion, see the Federal Register notice, Clarification of the Regulatory Determination for Waste from the Exploration, Development, and Production of Crude Oil, Natural Gas and Geothermal Energy, March 22, 1993, Federal Register Volume 58, Pages 15284 to 15287.

Exempt/Non-Exempt Wastes



What happens if "exempt" and "non-exempted" wastes are mixed?
Mixing wastes, particularly exempt and non-exempt wastes, creates additional considerations. Determining whether a mixture is an exempt or non-exempt waste requires an understanding of the nature of the wastes prior to mixing and, in some instances, might require a chemical analysis of the mixture. Whenever possible, avoid mixing non-exempt wastes with exempt wastes. If the non-exempt waste is a listed or characteristic hazardous waste, the resulting mixture might become a non-exempt waste and require management under RCRA Subtitle C regulation. Furthermore, mixing a characteristic hazardous waste with a non-hazardous or exempt waste for the purpose of rendering the hazardous waste non-hazardous or less hazardous might be considered a treatment process subject to appropriate RCRA Subtitle C hazardous waste regulation and permitting requirements.

How do I determine if a mixture of wastes is exempt or non-exempt?

Below are some basic guidelines for determining if a mixture is an exempt or non-exempt waste under the present mixture rule.

A. A mixture of an exempt waste with another exempt waste remains exempt. For example: A mixture of stimulation fluid that returns from a well with produced water results in an exempt waste.

B. Mixing a non-hazardous waste (exempt or non-exempt) with an exempt waste results in a mixture that is also exempt. For example: If non-hazardous wash water from rinsing road dirt off equipment or vehicles is mixed with the contents of a reserve pit containing only exempt drilling waste, the wastes in the pit remain exempt regardless of the characteristics of the waste mixture in the pit.

C. If, after mixing a non-exempt characteristic hazardous waste with an exempt waste, the resulting mixture exhibits any of the same hazardous characteristics as the hazardous waste (ignitability, corrosivity, reactivity, or toxicity), the mixture is a non-exempt hazardous waste.

- **a.** Example: If, after mixing non-exempt caustic soda (NaOH) that exhibits the hazardous characteristic of corrosivity in a pit containing exempt waste, the mixture also exhibits the hazardous characteristic of corrosivity as determined from pH or steel corrosion tests, then the entire mixture becomes a non-exempt hazardous waste.
- **b.** Example: If, after mixing a non-exempt solvent containing benzene with an exempt waste also containing benzene, the mixture exhibits the hazardous characteristic for benzene, then the entire mixture becomes a non-exempt hazardous waste.

D. If, after mixing a non-exempt characteristic hazardous waste with an exempt waste, the resulting mixture does not exhibit any of the same characteristics as the hazardous waste, the mixture is exempt. Even if the mixture exhibits some other characteristic of a hazardous waste, it is still exempt.

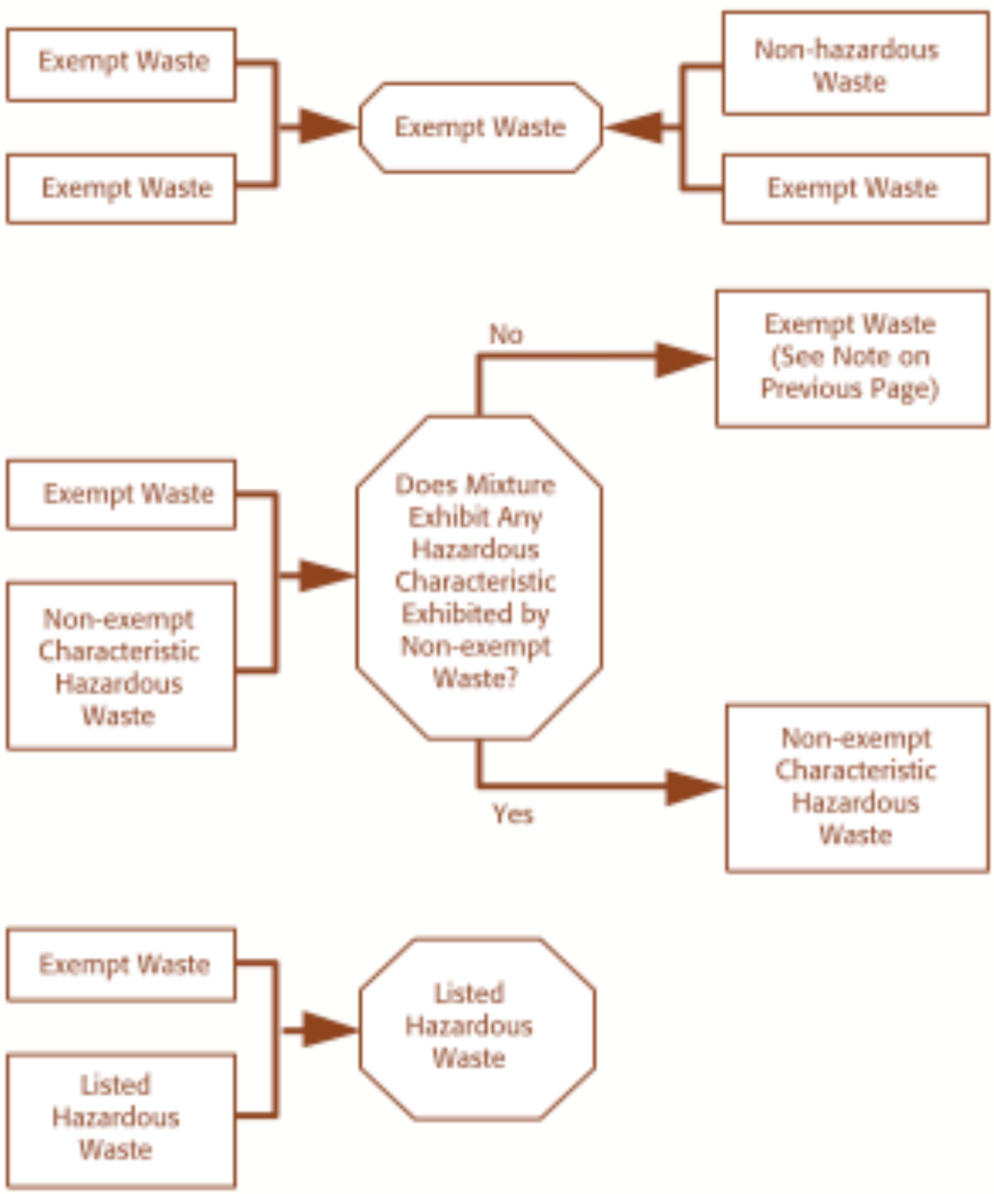
- **a.** Example: If, after mixing non-exempt hydrochloric acid (HCl) that only exhibits the corrosive characteristic with an exempt waste, the mixture does not exhibit the hazardous characteristic of corrosivity but does exhibit some other hazardous characteristic such as toxicity, then the mixture is exempt.
- **b.** Example: If, after mixing a non-exempt waste exhibiting the hazardous characteristic for lead with an exempt waste exhibiting the characteristic for benzene, the mixture exhibits the characteristic for benzene but not for lead, then the mixture is exempt.

E. Generally, if a listed hazardous waste is mixed with an exempt waste, regardless of the proportions, the mixture is a non-exempt hazardous waste. For example: If any amount of leaded tank bottoms from the petroleum refining industry (listed as waste code K052) is mixed with an exempt tank bottom waste, the mixture is considered a hazardous waste and is therefore non- exempt.

F. It is also important to emphasize that a mixture of an exempt waste with a listed hazardous waste generally becomes a non-exempt hazardous waste regardless of the relative volumes or concentrations of the wastes. However, if the listed hazardous waste was listed solely for one or more of the characteristics of ignitability, corrosivity, or reactivity, then a mixture of this waste with an exempt waste would only become non-exempt if the mixture exhibits the characteristic for which the hazardous waste was listed (i.e., if the mixture is ignitable, corrosive, or reactive).

G. Similarly, if a mixture of an exempt waste with a non-exempt characteristic hazardous waste exhibits any of the same hazardous waste characteristics as the hazardous waste, or if it exhibits a characteristic that would not have been exhibited by the exempt waste alone, the mixture becomes a non- exempt hazardous waste regardless of the relative volumes or concentrations of the wastes. In other words, for any of these scenarios, the wastes could become non-exempt even if only one barrel of hazardous waste were mixed with 10,000 barrels of exempt waste.

Possible Waste Mixtures and Their Exempt and Non-Exempt Status



What are best management practices for E&P waste?

The following are suggested E&P best waste management practices that should be deployed to protect human health and the environment.

A. Size reserve pits properly to avoid overflows
B. Use closed loop mud systems when practical, particularly with oil-based muds.
C. Review material safety data sheets (MSDSs) of materials used, and select less toxic alternatives when possible.
D. Minimize waste generation, such as by designing systems with the smallest volumes possible (e.g., drilling mud systems).
E. Reduce the amount of excess fluids entering reserve and production pits.
F. Keep non-exempt wastes out of reserve or production pits.
G. Design the drilling pad to contain storm water and rig wash.
H. Recycle and reuse oil-based muds and high-density brines when practical.
I. Perform routine equipment inspections and maintenance to prevent leaks or emissions.
J. Reclaim oily debris and tank bottoms when practical.
K. Minimize the volume of materials stored at facilities.
L. Construct adequate berms around materials and waste storage areas to contain spills.
M. Perform routine inspections of materials and waste storage areas to locate damaged or leaking containers.
N. Train personnel to use sensible waste management practices.

B. Naturally Occurring Radioactive Material

What are naturally occurring radioactive materials?

Naturally Occurring Radioactive Materials (NORMs), also known as Technically Enhanced NORMs, are natural materials that emit ionizing radiation. NORMs are found throughout our environment as well as in association with some oil and gas production operations.

NORMs may be found in scale and sludge deposits in surface equipment such as separators, heater treaters, pumps, and tubing.

What should one do to identify if NORMs are an issue on a site?

Surveys should be conducted on all surface equipment prior to any maintenance activities to determine whether NORMs are present from that specific reservoir.

If equipment may contain NORMs, what should an operator do?

Operators and/or their employees should abide by the following when performing maintenance activities on equipment that may contain NORMs:

i. Do not eat, drink, smoke, dip or engage in any other ingesting activities while working on equipment containing NORMs. Once work is completed, leave the area and wash hands and face with soap and warm water;
ii. Keep open cuts and sores covered;
iii. Keep hands away from eyes and mouth while working or when wearing protective gloves or other equipment; and
iv. Wear appropriate clothing and protective equipment as instructed by health and safety officials.

C. National Environmental Policy Act

What is the purpose of the National Environmental Policy Act (NEPA)?

Signed into law by President Richard Nixon on January 1, 1970, NEPA advanced an interdisciplinary approach to Federal project planning and decision making through environmental impact assessment. This approach requires Federal officials to consider environmental values alongside the technical and economic considerations that are inherent factors in Federal decision making.

Each Federal agency has its own agency NEPA implementing procedures which adapt the framework established by the CEQ regulations to address agency specific missions and decision making authority. The NEPA process begins when an agency proposes to take an action (this can include proposals to adopt: rules and regulations; formal plans that direct future actions; program; and specific projects – (see 40 C.F.R. **§** 1508.18). Once the proposal is conceptualized and any reasonable alternatives have been developed, the agency must determine if the action has the potential to affect the quality of the human environment. This process results in one of three levels of NEPA analysis. Agencies may:

- apply a Categorical Exclusion;
- prepare an Environmental Assessment (EA); or
- prepare an Environmental Impact Statement (EIS).

NEPA is intended to facilitate public participation and disclosure in the federal planning process, and also helps federal government officials "make decisions that are based on understanding of environmental consequences, and take actions that protect, restore, and enhance the environment" (40 CFR 1500.1(c)). The NEPA process analyzes and discloses the significant impacts a proposed action may have on the quality of the human environment.

As an operator, what do I have to do comply with NEPA in Osage County?

The Bureau of Indian Affairs (BIA) is required to comply with the National Environmental Policy Act of 1969 (NEPA), which mandates that all activities either funded or approved by a federal agency must complete the NEPA compliance process. Approval of any permit or lease associated with the BIA's management of the Osage Nation's Minerals Estate constitutes a major federal action as defined under the Council of Environmental Quality regulations in 40 CFR 1508.18(b)). Under 25 CFR 226.16: Commencement of Operations, the Agency requires the lessee to submit applications on forms to be furnished by the Superintendent and to secure his/her approval before well drilling, treating, or workover operations are started on the premises. It is during this process of permit approval that both the operator and the Agency should review, identify, and address any NEPA issues.

The BIA must demonstrate compliance with NEPA either by showing that the action qualifies for a categorical exclusion, or by having the operator complean environmental review which may require Environmental Assessment (EA) and/or an Environmental Impact Statement (EIS).

In accordance with 40 C.F.R. § 1506.5(b), it shall be the responsibility of the applicant (Lessees, including his or her contractor) to conduct and complete all environmental reviews for proposed actions requiring federal approval.

Environmental reviews must be written in accordance with Title 43, C.F.R. Part 46, Implementation of the National Environmental Policy Act of 1969 for the Department of the Interior, and 59 Indian Affairs Manual 3-H, the BIA NEPA Guidebook (2012), or must fall under the Department of the Interior's approved categorical exclusion list. Please refer to the following website for an electronic copy of these guidance documents:

http://www.bia.gov/WhatWeDo/Knowledge/Directives/Handbooks/index.htm

Completed environmental review documents must be submitted to the BIA Osage Agency for approval prior to the submission of an Application for Permit to Drill (APD) as the environmental review document is a mandatory component of the permit application package. This requirement applies to the following BIA permit approvals including, but not limited to, drilling, plugging, deepening, plugging back, conversion, casing alternation, and/or formation treatment.

D. Migratory Birds

What are migratory birds and who has legal responsibility for protecting them?

In 1918, the United States Congress enacted the Federal Migratory Bird Treaty Act (MBTA) that provides for the controlled harvest and protection of migratory birds. The Act makes the illegal death of any migratory bird a violation of Federal law, punishable by up to $15,000 in fines and possible criminal prosecution. The U.S. Fish and Wildlife Service, a branch of the U.S. Department of the Interior, enforces the law.

What do migratory birds have to do with gas and oil production?

The enforcement of the MBTA, has increased since the 1990s with several operators being found guilty of illegally taking or killing migratory birds which have been injured or killed as a result of contact with oil or saltwater in pits or open tanks. Nearly all birds of the Mid-Continent area are protected under the Act, including the common sparrow.

What are best management practices for protecting migratory birds?

Placing cover materials over potential hazards are the single most effective means to protect migratory birds and avoid any violations of the MBTA. Best practices include, but are not limited to:

i. Cover open top tanks and permanent pits, such as skimming pits or emergency saltwater storage pits with a net, screen, or other material.
ii. Materials to cover open top tanks include solid wood, steel, or fiberglass covers, or flexible screen or net. Flexible netting includes chicken wire and polypropylene. However, chicken wire is cumbersome to work with and doesn't last long. Polypropylene netting with a one-inch mesh size is popular for open top tanks. Netting with a one-inch mesh is needed to prevent small birds from getting into the tank.
iii. The best way to cover pits is with the polypropylene net using a tie down and support system to secure the net. Securing the net extends its life. Some operators may cover their tanks themselves or may hire one of several companies in the area that furnish and install protective netting.

What happens if an operator harms migratory birds?

Harm to migratory birds is subject to any number of civil and criminal penalties. These are defined by statute and regulation. In addition, should a spill be the cause of harm, the Oil Pollution Act of 1990 provides for a Natural Resource Damage Assessment and Restoration process for developing a restoration plan and pursuing implementation of restoration through funding by the responsible parties.

E. Endangered Species

What is the purpose of the Endangered Species Act (ESA)?

The purpose of the ESA is to protect and recover imperiled species and the ecosystems upon which they depend. The U.S. Fish and Wildlife Service and the Commerce Department's National Marine Fisheries Service (NMFS) administer the act. The FWS has primary responsibility for terrestrial and freshwater organisms, while the responsibilities of NMFS are mainly marine wildlife such as whales and anadromous fish such as salmon.

Under the ESA, species may be listed as either endangered or threatened. "Endangered" means a species is in danger of extinction throughout all or a significant portion of its range. "Threatened" means a species is likely to become endangered within the foreseeable future. All species of plants and animals, except pest insects, are eligible for listing as endangered or threatened. For the purposes of the ESA, Congress defined species to include subspecies, varieties, and, for vertebrates, distinct population segments.

What are species are listed under the Endangered Species Act (ESA) in Osage County?

Official county lists of federally threatened and endangered species are maintained by the U.S. Fish and Wildlife Service, the federal agency that administers the Endangered Species Act in Oklahoma. Please consult the U.S Fish and Wildlife Service (USFWS) for the most up-to-date list of endangered or threatened species. The following species are of concern in Osage County as of the writing of this Manual.

- American Burying Beetle -- Endangered
- American Peregrine Falcon -- Recovery
- Eskimo Curlew Endanger -- Possibly extinct
- Interior Least Tern -- Endangered
- Whooping Crane -- Endangered
- Piping Plover --Threatened
- Neosho Mucket Mussel -- Candidate

As an operator, what do I have to do comply with the ESA in Osage County?

A general environmental review, including the review of any potential presence of any endangered species or habitat, should take place after the approval of a lease but before approval of a drilling permit by the Osage Agency. Under 25 CFR 226.16: Commencement of Operations, the Agency requires the lessee to submit applications on forms to be furnished by the Superintendent and to secure his/her approval before well drilling, treating, or workover operations are started on the premises. It is during this process of permit approval, as part of NEPA compliance that both the operator and the Agency shall review, identify, and address any ESA issues.

REMEDIATION AND RESTORATION

REMEDIATION AND RESTORATION

A. Remediation/Restoration of Soil Contaminated with Produced Fluids, including Salt Water

Do I have to remediate soils contaminated with produced fluids, including salts?

Yes. Whenever practical, unless otherwise agreed to by the operator and the landowner, contaminated soil will be restorted to the ability to sustain plant growth.

How might I remediate soils contaminated with oils?

Oil contaminated soils should be treated with nutrient addition in cas of extreme contamination only. Natural bioremediation of petreleum hydrocarbons is expected in almost all cases after the free product is picked up

The conventional flushing-picking up produced fluids from contaminated soils with freswhater may remove enough of the contaminant that futher treatment is not necessary. The operator should be careful that any flushing does not cause contamination to any surface waterways. The contaminated site should be observed for a reasonable period of time to determine if plant life has been adversely affected. Soil testing may be required in some cases

How might I remediate soils contaminated with salts?

Salt water contaminated soils which are unable to to sustain plant growth after flushing with freshwater should be tested to determined the extent of contamination and soil characterists. After testing, appropriate treatment can be applied Examples of possible treatments are shown below.

1. Addition of gypsum ($CaSO_4$) to initiate base exchange.
2. Tilling of the soil to promote moister infiltration and leaching of the sodium solubilization of the gypsum and promotion of bioactivity.
3. Addition of a bulking agent and nutrient source such as such manure or hay.
4. Contouring to prevent erosion.
5. Addition of moisture.
6. Planting of salt tolerant grasses or plants.
7. Fencing of the remediate site to prevent livestock from interfering with the site.

Other guidance is available, for instance, with the OCC and its saltwater spill clean up brochure here: http://www.occeweb.com/og/publications.htm)

EMERGENCY PLANNING AND PREPARATION

A. Emergency Planning and Community Right to Know Act (EPCRA)

Congress passed the Emergency Planning and Community Right-to-Know Act (EPCRA) in 1986. Also known as SARA Title III, this act establishes requirements for federal, state and local governments, Indian tribes, and industry regarding emergency planning and "Community Right-to-Know" reporting on hazardous and toxic chemicals. The Community Right-to-Know provisions help increase public's knowledge and access to information on chemicals at individual facilities, their uses, and releases into the environment. States and communities, working with facilities, can use the information to improve chemical safety and protect public health and the environment.

What Does EPCRA Cover?

EPCRA has four major provisions:

- Emergency planning (sections 301-303),
- Emergency release notification (section 304),
- Hazardous chemical storage reporting requirements (sections 311-312), and
- Toxic chemical release inventory (section 313).

Information collected from these four requirements helps states and communities develop a broad perspective of chemical hazards for the entire community, as well as for individual facilities.

Regulations implementing EPCRA are found in Title 40 of the Code of Federal Regulations, parts 350 to 372. The chemicals covered by each of the sections are different, as are the quantities that trigger reporting. Table 1 summarizes the chemicals and thresholds.

What Are Emergency Response Plans (Sections 301-303)?

Emergency Response plans contain information that community officials can use at the time of a chemical accident. Community emergency response plans for chemical accidents were developed under Section 303. LEPCs are required to update these plans annually. The plans must:

- Identify facilities and transportation routes of extremely hazardous substances;
- Describe emergency response procedures, on and off site;

- Designate a community coordinator and facility coordinator(s) to implement the plan;
- Outline emergency notification procedures;
- Describe how to determine the probable affected area and population by releases;
- Describe local emergency equipment and facilities and the persons responsible for them;
- Outline evacuation plans;
- Provide a training program for emergency responders (including schedules); and,
- Provide methods and schedules for exercising emergency response plans.

Planning activities of LEPCs and facilities initially focused on, but were not limited to, the 406 extremely hazardous substances (EHSs) listed by EPA in 1987 (now currently 355 chemicals).The list includes the threshold planning quantities (minimum limits) for each substance. Any facility that has EHS at or above its threshold planning quantity must notify the State Emergency Response Commission (SERC) or the Tribal Emergency Response Commission (TERC) and Local Emergency Planning Committee (LEPC) within 60 days after they first receive a shipment or produce the substance on site.

What Are the Emergency Notification Requirements (Section 304)?

Facilities must immediately notify (Oklahoma Dept. of Environmental Quality) the LEPC and the SERC or the TERC if there is a release into the environment of a hazardous substance that is equal to or exceeds the minimum reportable quantity set in the regulations. This requirement covers the 355 extremely hazardous substances, as well as the more than 700 hazardous substances subject to the emergency notification requirements under CERCLA section 103(a)(40 CFR 302.4). Some chemicals are common to both lists. Initial notification can be made by telephone, radio, or in person.

Emergency notification requirements involving transportation incidents can be met by dialing 911, or in the absence of a 911 emergency number, calling the operator. This emergency notification needs to include:

- The chemical name;
- An indication of whether it is an extremely hazardous substance;
- An estimate of the quantity released into the environment;
- The time and duration of the release;
- Whether the release occurred into air, water, and/or land;
- Any known or anticipated acute or chronic health risks associated with

- the emergency, and where necessary, advice regarding medical
- attention for exposed individuals;
- Proper precautions, such as evacuation or sheltering in place; and,
- Name and telephone number of contact person.
- A written follow-up notice must be submitted to the SERC or the TERC and LEPC as soon as practicable after the release. The follow-up notice must update information included in the initial notice and provide information on actual response actions taken and advice regarding medical attention necessary for citizens exposed.

What Are the Community Right-to-know Requirements (Sections 311 and 312)?

Under Occupational Safety and Health Administration (OSHA) regulations, employers must maintain a material safety data sheet (MSDS) for any hazardous chemicals stored or used in the work place. Approximately 500,000 products are required to have MSDSs. Section 311 requires facilities that have MSDSs for chemicals held above certain threshold quantities to submit either copies of their MSDSs or a list of these chemicals to the SERC or TERC, LEPC, and local fire department. If the facility owner or operator chooses to submit a list of chemicals, the list must include the chemical or common name of each substance and must identify the applicable hazard categories.

These hazard categories are:
- Immediate (acute) health hazard;
- Delayed (chronic) health hazard;
- Fire hazard;
- Sudden release of pressure hazard; and
- Reactive hazard.

If a list is submitted, the facility must submit a copy of the MSDSs for any chemical on the list upon request by the LEPC.

Facilities that start using a hazardous chemical or increase the quantity to exceed the thresholds must submit MSDSs or a list of MSDSs chemicals within three months after they become covered. Facilities must provide a revised MSDS to update the original MSDS or list if significant new information is discovered about the hazardous chemical.

Facilities covered by Section 311 must submit annually an Emergency and

Hazardous Chemical Inventory Form to Oklahoma Department of Environmental Quality and the local fire department as required under Section 312. Facilities provide Tier II inventory form.

Who must file Tier II forms (hazardous chemical reporting requirements) under Section 312 of the Emergency Planning and Community Right-to-Know Act (EPCRA) (40 CFR §370.10) ?

Your facility must comply with the reporting requirements of this part if the Occupational Safety and Health Administration's (OSHA) Hazard Communication Standard (HCS) require your facility to prepare or have available a Material Safety Data Sheet (MSDS) for a hazardous chemical and if either of the following conditions is met:

a. A hazardous chemical that is an Extremely Hazardous Substance (EHS) is present at your facility at any one time in an amount equal to or greater than 500 pounds (227 kg—approximately 55 gallons) or the Threshold Planning Quantity (TPQ), whichever is lower. EHSs and their TPQs are listed in Appendices A and B of 40 CFR part 355.

b. A hazardous chemical that is not an EHS is present at your facility at any one time in an amount equal to or greater than the threshold level for that hazardous chemical. Threshold levels for such hazardous chemicals are:

   i. For any hazardous chemical that does not meet the criteria in paragraph (a)(2)(ii) or (iii) of this section, the threshold level is 10,000 pounds (or 4,540 kg). (This would include crude oil, condensate, or other hazardous chemicals stored in tanks).

   ii. For gasoline at a retail gas station (For purposes of this part, retail gas station means a retail facility engaged in selling gasoline and/or diesel fuel principally to the public, for motor vehicle use on land.), the threshold level is 75,000 gallons (approximately 283,900 liters) (all grades combined). This threshold is only applicable for gasoline that was in tank(s) entirely underground and was in compliance at all times during the preceding calendar year with all applicable Underground Storage Tank (UST) requirements at 40 CFR part 280 or requirements of the state UST program approved by the Agency under 40 CFR part 281.

iii. For diesel fuel at a retail gas station (For purposes of this part, retail gas station means a retail facility engaged in selling gasoline and/or diesel fuel principally to the public, for motor vehicle use on land.), the threshold level is 100,000 gallons (approximately 378,500 liters) (all grades combined). This threshold is only applicable for diesel fuel that was in tank(s) entirely underground and was in compliance at all times during the preceding calendar year with all applicable Underground Storage Tank (UST) requirements at 40 CFR part 280 or requirements of the state UST program approved by the Agency under 40 CFR part 281.

What information must I provide and what format must I use (§370.40)?

a. If you are required to comply with the hazardous chemical reporting requirements of this part, then by March 1 every year you must submit inventory information regarding any hazardous chemical present at your facility at any time during the previous calendar year in an amount equal to or in excess of its threshold level.

b. You must submit Tier II information to the SERC, LEPC, or fire department having jurisdiction over your facility. EPA publishes Tier II Inventory Forms that provide uniform formats for reporting the Tier I and Tier II information. You may use a State or local format for reporting inventory information. In Oklahoma, you are required to file electronically, using the Tier II Submit software.

c. You should contact the SERC to determine that State's requirements for inventory reporting formats, procedures, and to obtain inventory forms.

d. In Oklahoma, you file the Tier II submit report to the Oklahoma Department of Environmental Quality (ODEQ), who will disseminate to the appropriate Local Emergency Planning Committee and fire department for the county in which your facility resides.

Where can I find more information about reporting Tier II information ?

You can also get up-to-date information by calling the ODEQ at **405-702-1013.**
You can get additional information by visiting the ODEQ website on Tier II reporting at:

http://www.deq.state.ok.us/LPDnew/saratitleiii/tierii.htm.

Instructions on using the Tier II submit software is located on this page.

Table 4: EPCRA Chemicals and Reporting Thresholds

	Section 302	Section 304	Sections 311/312	Section 313
Chemicals Covered	355 Extremely Hazardous Substances	> 1,000 substances	Approx. 500,000 Hazardous chemical	>650 Toxic Chemicals and categories
Thresholds	Threshold Planning Quantity 1-10,000 pounds on site at any one time	Reportable quantity, 1-5,000 lbs, released in a 24 hour period.	500 pounds or TPQ, whichever is less for EHSs; 75,000 gallons for gasoline; 100,000 gallons for diesel and 10,000 pounds for all other hazardous chemicals.	25,000 pounds per year manufactured or processed; 10,000 pounds a year otherwise used; persistent bioaccumulative toxics have lower thresholds.

What is the Toxics Release Inventory (Section 313)?

Section 313 of EPCRA established the Toxics Release Inventory. TRI tracks the management of certain toxic chemicals that pose a threat to human health and the environment. Facilities in different industry sectors must annually report how much of each chemical they managed through recycling, energy recovery, treatment and environmental releases. TRI reporting forms must be submitted to EPA and the appropriate state or tribe by July 1 of each year. These forms cover environmental releases and other management of toxic chemicals that occurred during the previous calendar year.

The information submitted by facilities is compiled in the Toxics Release Inventory and made available to the public through the TRI website: www.epa.gov/tri.

TRI helps support informed decision-making by industry, government, non-governmental organizations and the public. TRI includes information about:

- On-site releases (including disposal) of toxic chemicals to air, surface water and land;
- On-site recycling, treatment and energy recovery associated with TRI chemicals;
- Off-site transfers of toxic chemicals from TRI facilities to other locations;
- Pollution prevention activities at facilities;
- Releases of lead, mercury, dioxin and other persistent, bioaccumulative and toxic (PBT) chemicals; and
- Facilities in a variety of industry sectors (including manufacturing, metal mining and electric power generation) and some federal facilities.

A complete list of covered facilities is available online:
http://www.epa.gov/tri/lawsandregs/naic/ncodes.htm.

Some of the ways TRI data can be used include:
- Identifying sources of toxic chemical releases;
- Beginning to analyze potential toxic chemical hazards to human health and the environment; and
- Encouraging pollution prevention at facilities.

Table 5: Reporting Schedules

Section	
302 **Community Emergency Response Plan**	One time notification to SERC/TERC and LEPC
304 **Emergency Release Notification**	Each time a release above a reportable quantity of an EHS or CERCLA Hazardous Substance occurs to LEPC and SERC or TERC
311 **Hazardous Chemical storage reporting requirements**	One time submission of MSDS or list of hazardous chemicals. An update is required for new chemicals or new information about chemicals already submitted to the SERC or TERC, LEPC, and the fire department with jurisdiction over the facility.

312 Hazardous Chemical storage reporting requirements: Tier I/ II reporting	Annually, by March 1 to SERC or TERC, LEPC, and the fire department with jurisdiction over the facility.
313 Toxic Release Inventory	Annually, by July 1, to EPA, states and tribes.

APPENDICES

Disclaimer - Appendix E

The sample Spill Prevention, Control and Countermeasure (SPCC) Plan in Appendix E is intended to provide examples and illustrations of how a production facility could address a variety of scenarios in its SPCC Plan. The "facility" is not an actual facility, nor does it represent any actual facility or company. Rather, EPA is providing illustrative examples of the type and amount of information that is appropriate SPCC Plan language for these hypothetical situations.

Because the SPCC rule is designed to give each facility owner/operator the flexibility to tailor the facility's SPCC Plan to the facility's circumstances, this sample SPCC Plan is not a template to be adopted by a facility; doing so does not mean that the facility will be in compliance with the SPCC rule requirements. Nor is the sample plan a template that must be followed in order for the facility to be considered in compliance with the SPCC rule.

SPILL PREVENTION, CONTROL, AND COUNTERMEASURE PLAN

Clearwater Oil Company

Big Bear Lease No. 2 Production Facility

5800 Route 417
Madison, St. Anthony Parish, Louisiana 73506

Clearwater

Prepared by
Montgomery Engineering, Inc.

November 23, 2003

Version 1.0, 11/28/2005

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Cross-Reference with SPCC Rule

* Only relevant rule provisions are indicated. For a complete list of SPCC requirements, refer to the full text of 40 CFR part 112.

Introduction

The purpose of this Spill Prevention Control and Countermeasure (SPCC) Plan is to describe measures implemented by Clearwater to prevent oil discharges from occurring, and to prepare Clearwater to respond in a safe, effective, and timely manner to mitigate the impacts of a discharge from the Big Bear Lease No. 2 production facility. This SPCC Plan has been prepared and implemented in accordance with the SPCC requirements contained in 40 CFR part 112.

In addition to fulfilling requirements of 40 CFR part 112, this SPCC Plan is used as a reference for oil storage information and testing records, as a tool to communicate practices on preventing and responding to discharges with Clearwater employees and contractors, as a guide on facility inspections, and as a resource during emergency response.

Management Approval

40 CFR 112.7

Clearwater Oil Company ("Clearwater") is committed to maintaining the highest standards for preventing discharges of oil to navigable waters and the environment through the implementation of this SPCC Plan. This SPCC Plan has the full approval of Clearwater management. Clearwater's management has committed the necessary resources to implement the measures described in this Plan.

Bill Laurier is the Designated Person Accountable for Oil Spill Prevention at this Clearwater facility and has the authority to commit the necessary resources to implement the Plan as described.

Authorized Facility Representative:	Bill Laurier
Signature:	*Bill Laurier*
Title:	Field Operations Manager
Date:	November 23, 2003

Professional Engineer Certification

40 CFR 112.3(d)

The undersigned Registered Professional Engineer is familiar with the requirements of Part 112 of Title 40 of the *Code of Federal Regulations* (40 CFR part 112) and has visited and examined the facility, or has supervised examination of the facility by appropriately qualified personnel. The undersigned Registered Professional Engineer attests that this Spill Prevention, Control, and Countermeasure Plan has been prepared in accordance with good engineering practice, including consideration of applicable industry standards and the requirements of 40 CFR part 112; that procedures for required inspections and testing have been established; and that this Plan is adequate for the facility. [112.3(d)]

This certification in no way relieves the owner or operator of the facility of his/her duty to prepare and fully implement this SPCC Plan in accordance with the requirements of 40 CFR part 112.

Peter E. Trudeau	*November 23, 2003*
Signature	Date

Peter E. Trudeau, P.E.
Name of Professional Engineer

90535055	*Louisiana*
Registration Number	Issuing State

PE Seal

Peter E. Trudeau
LA #90535055

Plan Review

40 CFR 112.5

In accordance with 40 CFR 112.5, Clearwater Oil periodically reviews and evaluates this SPCC Plan for any change in the facility design, construction, operation, or maintenance that materially affects the facility's potential for an oil discharge. Clearwater reviews this SPCC Plan at least once every five years. Revisions to the Plan, if any are needed, are made within six months of this five-year review. Clearwater will implement any amendment as soon as possible, but not later than six months following preparation of any amendment. A registered PE certifies any technical amendment to the Plan, as described above, in accordance with 40 CFR 112.3(d).

Scheduled five-year reviews and Plan amendments are recorded in Table 0-1. This log must be completed even if no amendment is made to the Plan. Unless a technical or administrative change prompts an earlier review, the next scheduled review of this Plan must occur by *November 23, 2008.*

Table 0-1: Record of Plan Review and Changes

Date	Authorized Individual	Review Type	PE Certification	Summary of Changes
11/23/03	Bill Laurier	Initial Plan	Yes	N/A
04/14/04	Bill Laurier	Off-cycle review	No	Changed telephone number for Field Operations Manager. Corrected page numbers in Table of Content. Non-technical amendments, no PE certification is needed.

Location of SPCC Plan

40 CFR 112.3(e)

In accordance with 40 CFR 112.3(e), and because the facility is normally unmanned, a complete copy of this SPCC is maintained at the field office closest to the facility, which is located approximately 25 miles from the facility at 2451 Mountain Drive, Ridgeview, LA. Additional copies are available at the Clearwater Oil Company management office, located at 13000 Main Street, Suite 400, Houston, TX.

Certification of Substantial Harm Determination

40 CFR 112.20(e), 40 CFR 112.20(f)(1)

Facility Name: **Clearwater Oil Company, Big Bear Lease No. 2**

1. Does the facility transfer oil over water to or from vessels and does the facility have a total oil storage capacity greater than or equal to 42,000 gallons?
   Yes ☐ No ■

2. Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and does the facility lack secondary containment that is sufficiently large to contain the capacity of the largest aboveground oil storage tank plus sufficient freeboard to allow for precipitation within any aboveground storage tank area?
   Yes ☐ No ■

3. Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and is the facility located at a distance (as calculated using the appropriate formula) such that a discharge from the facility could cause injury to fish and wildlife and sensitive environments?
   Yes ☐ No ■

4. Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and is the facility located at a distance (as calculated using the appropriate formula) such that a discharge from the facility would shut down a public drinking water intake?
   Yes ☐ No ■

5. Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and has the facility experienced a reportable oil spill in an amount greater than or equal to 10,000 gallons within the last 5 years?
   Yes ☐ No ■

Certification

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this document, and that based on my inquiry of those individuals responsible for obtaining this information, I believe that the submitted information is true, accurate, and complete.

Bill Laurier	*Field Operations Manager*
Signature	Title
Bill Laurier	*November 23, 2003*
Name (type or print)	Date

PART I - GENERAL FACILITY INFORMATION

40 CFR 112.7(a)(3)

1.1 Company Information

Name of Facility:	Clearwater Oil Company Big Bear Lease No. 2
Type	Onshore oil production facility
Date of Initial Operation	2002
Location	5800 Route 417 Madison, St. Anthony Parish, Louisiana 73506
Name and Address of Owner	Clearwater Oil Company *Regional Field Office* 2451 Mountain Drive Ridgeview, LA 70180 *Corporate Headquarters* 13000 Main Street, Suite 400 Houston, TX 77077

1.2 Contact Information

The designated person accountable for overall oil spill prevention and response at the facility, also referred to as the facility's "Response Coordinator" (RC), is the Field Operations Manager, Bill Laurier. 24-hour contact information is provided in Table 1-1.

Personnel from Avonlea Services Inc. ("Avonlea") provide operations (pumper/gauger) support activities to Clearwater field personnel, including performing informal daily examinations of the facility equipment, as described in Section 3.4 of this SPCC Plan. Avonlea personnel regularly visit the facility to record production levels and perform other maintenance/inspection activities as requested by the Clearwater Field Operations Manager. Key contacts for Avonlea are included in Table 1-1.

Table 1-1: Facility contact information

Name	Title	Telephone	Address
Lester Pearson	Vice-President of Operations Clearwater Oil Co.	(555)-289-4500	13000 Main Street, Suite 400 Houston, TX 77077
Carol Campbell	Regional Director of Operations Clearwater Oil Co.	(405) 831-6320 (office) (405) 831-2262 (cell)	2451 Mountain Drive Ridgeview, LA 70180
Bill Laurier	Field Operations Manager Clearwater Oil Co.	(405) 831-6322 (office) (405) 829-4051 (cell)	2451 Mountain Drive Ridgeview, LA 70180
Joe Clark	Field Supervisor Avonlea Services, Inc.	(406) 545-2285 (office) (406) 549-9087 (cell)	786 Cherry Creek Road Avonlea, LA 70180
William Mackenzie	Pumper Avonlea Services, Inc.	(406) 549-9087 (cell)	786 Cherry Creek Road Avonlea, LA 70180

1.3 Facility Layout Diagram

Appendix A, at the end of this Plan, shows a general site plan for the facility. The site plan shows the site topography and the location of the facility relative to waterways, roads, and inhabited areas. Appendix A also includes a detailed facility diagram that shows the wells, flowlines, tank battery, and transfer areas for the facility. The diagram shows the location, capacity, and contents of all oil storage containers greater than 55 gallons in capacity.

1.4 Facility Location and Operations

Clearwater owns and operates the Big Bear Lease No. 2 production facility, which is located approximately six miles north of Madison, St. Anthony Parish, Louisiana (see Figure A-1 in Appendix A). The site is accessed through a private dirt/gravel road off Route 417.

As illustrated in Figure A-2 in Appendix A, the facility is comprised of five main areas: Well A, Well B, the saltwater disposal well, flowlines, and a tank battery. The tank battery includes three 400-barrel (bbl) oil storage tanks, one 500-bbl produced water tank, one 500-bbl gun barrel, and associated flowlines and piping.

The production facility is generally unmanned. Clearwater's field office is located 25 miles from the site, at 2541 Mountain Drive, Ridgeview, Louisiana. Field operations personnel from Clearwater, or pumpers acting as contractors to Clearwater visit the facility daily (2-4 hours each day) to record production rates and ensure the proper functioning of wellhead equipment and pumpjacks, storage tanks, flowlines, and separation vessels. This includes performing equipment inspections and maintenance as needed.

The facility produces an average of 30 bbl (1,260 gallons) of crude oil (approximately 40 API gravity) and 140 bbl (5,880 gallons) of produced water each day. The produced water tank contains an oil/produced water mixture. It is subject to 40 CFR part 112 and is covered by this SPCC Plan.

1.5 Oil Storage and Handling

1.5.1 Production Equipment

Oil storage at the facility consists of one (1) 500-bbl gun barrel, three (3) 400-bbl aboveground storage tanks, one (1) 500-bbl produced water tank, and associated piping, as summarized in Table 1-2. The total oil capacity at this facility is 2,200 bbl (92,400 gallons).

All oil storage tanks are shop-built and meet the American Petroleum Institute (API) tank construction standard. Their design and construction are compatible with the oil they contain and the temperature and pressure conditions of storage. Tanks storing crude or produced oil (#1 through #4) are constructed of welded steel following API-12F *Shop Welded Tanks for Storage of Production Liquids* specifications. Steel tanks are coated to minimize corrosion. Tank holding produced water (#5) constructed of fiberglass following API-12P *Fiberglass Reinforced Plastic Tanks* specifications.

Other production equipment present at the facility include the pumpjacks at each well and water pumps for transfer of saltwater to the injection well. These store a minimal amount of lubricating oil (less than 55 gallons). Lubricating oil and other substances, such as solvents and chemicals for downhole treatment, are also stored at the facility, but in quantities below the 55-gallon threshold for SPCC applicability. Table 1-2 lists all oil containers present at the facility with capacity of 55 gallons or more.

Table 1-2: Characteristics of oil containers

ID	Type	Construction	Primary Content	Capacity (barrels)	Capacity (gallons)
#1	Gun barrel	Steel	Oil	500	21,000
#2	AST	Steel	Oil	400	16,800
#3	AST	Steel	Oil	400	16,800
#4	AST	Steel	Oil	400	16,800
#5	AST	Fiberglass	Produced water and oil mixture	500	21,000
			TOTAL	2,200	92,400

1.5.2 Transfer Activities

Wells A and B produce crude oil, produced water (saltwater), and small amounts of natural gas. The oil and water are produced through the tubing, while the natural gas is produced through the casing. Well liquids are then routed via 2-inch steel flowlines to the gun barrel tank for separation, while the gas is sent to a flare. Produced saltwater is routed from the gun barrel to the 500-bbl saltwater storage tank first, then is pumped through flowlines to the saltwater disposal well where it is injected. The disposal well is located approximately 2,000 ft to the west of the tank battery. The crude oil is sent to the three 400-bbl (16,800-gallon) oil storage tanks.

Crude oil from the lease is purchased by Clearwater's crude oil purchaser and transported from the facility by the purchaser's tanker truck. Although daily well production rates may vary, enough crude is produced and stored for approximately one 180-bbl (7,560-gallon) load of oil to be picked up weekly by the transporter. The largest tanker truck visiting the facility has a total capacity of 210 bbl (8,820 gallons). Tanker trucks come to the facility only to transfer crude oil and do not remain at the facility. All transfer operations are attended by the trucker or by field operations personnel and meet the minimum requirements of the U.S. Department of Transportation Hazardous Materials Regulations. Appendix B to this Plan summarizes the Tank Truck Loading Procedure at this facility.

Produced saltwater is pumped via transfer pumps from the saltwater tank to the saltwater disposal well, located approximately 2,000 feet west of the facility, by 2-inch PVC flowlines (FLSW). The disposal well meets all requirements of the Underground Injection Control (UIC) program (40 CFR parts 144-148).

1.6 Proximity to Navigable Waters

The facility is located within the Mines River watershed, approximately half a mile to the west of Big Bear Creek, and six miles North of the Mines River. The wells and tank battery are situated on relatively level ground that slopes in a general southeastern direction. The site plan in Figure A-1 in Appendix A shows the location of the facility relative to nearby waterways. The facility diagram included in Figure A-2 in Appendix A indicates the general direction of drainage. In the event of an uncontrolled discharge from the wells, flowlines, or the tank battery areas, oil would follow the natural topography of the site and flow into Big Bear Creek. Big Bear Creek meets with the Mines River to the south just before the town of Madison. The River then flows in a general easterly direction following Route 101.

1.7 Conformance with Applicable State and Local Requirements [112.7(j)]

The SPCC regulation at 40 CFR part 112 is more stringent than requirements from the state of Louisiana for this type of facility. This SPCC Plan was written to conform with 40 CFR part 112 requirements. The facility thereby conforms with general requirements for oil pollution facilities in Louisiana. All discharge notifications are made in compliance with local, state, and federal requirements.

PART II. SPILL RESPONSE AND REPORTING

40 CFR 112.7

2.1 Discharge Discovery and Reporting [112.7(a)(3)]

Several individuals and organizations must be contacted in the event of an oil discharge. The Field Operations Manager is responsible for ensuring that all required discharge notifications have been made. All discharges should be reported to the Field Operations Manager. The summary table included in Appendix F to this SPCC Plan provides a list of agencies to be contacted under different circumstances. Discharges would typically be discovered during the inspections conducted at the facility in accordance with procedures set forth in Section 3.4.1 of this SPCC Plan, Table 3-3 and Table 3-4, and on the checklist of Appendix C. The Form included in Appendix F of this Plan summarizes the information that must be provided when reporting a discharge, including contact lists and phone numbers.

2.1.1 Verbal Notification Requirements (Local, State, and Federal (40 CFR part 110))

Any unauthorized discharge into air, land or water must be reported immediately to the State Police and the Emergency Planning Commission as soon as the discharge is detected.

For any discharge that reaches navigable waters, or threatens to reach navigable waters, *immediate* notification must be made to the National Response Center Hotline (800-424-8802) and to the Environmental Protection Agency.

In the event of a discharge that threatens to result in an emergency condition, facility field personnel must verbally notify the Louisiana Emergency Hazardous Materials Hotline (225-925-6595) immediately, and in no case later than *within one (1) hour* of the discovery of the discharge. An emergency condition is any condition that could reasonably be expected to endanger the health and safety of the public; cause significant adverse impact to the land, water, or air environment; or cause severe damage to property. This notification must be made regardless of the amount of the discharge.

In the event of a discharge that does not present an emergency situation, verbal notification must be made to the Office of Environmental Compliance (by telephone at 225-763-3908 during office hours or 225-342-1234 after hours, weekends, and holidays; or by e-mail utilizing the Incident Report Form and procedures found at www.deq.state.la.us/surveillance) *within twenty-four (24) hours* of the discovery of the discharge.

2.1.2 Written Notification Requirements (State and Federal (40 CFR part 112))

A written notification will be made to EPA for any single discharge of oil to a navigable waters or adjoining shoreline waterway of more than 1,000 gallons, or for two discharges of 1 bbl (42 gallons) of oil to a waterway in any 12-month period. This written notification must be made within 60 days of the qualifying discharge, and a copy will be sent to the Louisiana Department of Environmental Quality (DEQ), which is the state agency in charge of oil pollution control activities. This reporting requirement is separate and in addition to reporting under 40 CFR part 110 discussed above.

For any discharge reported verbally, a written notification must also be sent to the DEQ and to the St. Anthony's Parish Local Emergency Planning Committee (LEPC), both within five (5) days of the qualifying discharge.

A written notification to the State Emergency Response Commission or LEPC is required for a discharge of 100 lbs or more beyond the confines of the facility (equivalent to 2 mcf of natural gas, or 13 gallons of oil) within five (5) days of the qualifying discharge.

2.1.3 Submission of SPCC Information

Whenever the facility experiences a discharge into navigable waters of more than 1,000 gallons, or two discharges of 42 gallons or more within a 12-month period, Clearwater will provide information in writing to the EPA Region 6 office within 60 days of a qualifying discharge as described above. The required information is described in Appendix F of this SPCC Plan.

2.2 Spill Response Materials

Boom, sorbent, and other spill response materials are stored in the shed next to the loading area and are accessible by Clearwater and Avonlea personnel. The response equipment inventory for the facility includes:

(4)	Empty 55-gallons drums to hold contaminated material
(3)	50-ft absorbent socks
(4)	10-ft sections of hard skirted deployment boom
(2)	50-ft floating booms
(200 pounds)	"Oil-dry" loose absorbent material
(4 boxes)	2 ft x 3 ft absorbent pads
(3 boxes)	Nitrile gloves
(3 boxes)	Neoprene gloves
(6 pairs)	Vinyl/PVC pull-on overboots
(3)	Non-sparking shovels
(3)	Brooms
(20)	Sand bags
(1)	Combustible Gas Indicator with H_2S detection capabilities

Additional equipment and material are also kept at the field office. The inventory is checked monthly by Clearwater field operations personnel to ensure that used material is replenished. Supplies and equipment may be ordered from:

(1) Rocky Mountain Equipment Co. (800) 959-3000
(2) Quick Sorbent (800) 857-4650.

2.3 Spill Mitigation Procedures

The following is a summary of actions that must be taken in the event of a discharge. It summarizes the distribution of responsibilities among individuals and describes procedures to follow in the event of a discharge.

A complete outline of actions to be performed in the event of a discharge from flowlines reaching or threatening to reach navigable waters is included in the facility Contingency Plan (see Appendix I of this SPCC Plan).

Reminder: *In the event of a discharge originating from Flowline A or Flowline B, facility personnel must immediately implement the Oil Spill Contingency Plan. The Oil Spill Contingency Plan discusses the additional procedures that must be followed to respond to a discharge of oil to navigable waters or adjoining shorelines.*

In the event of a discharge, Clearwater or contractor field personnel and the Field Operations Manager shall be responsible for the following:

2.3.1 Shut Off Ignition Sources

Field personnel must shut off all ignition sources, including motors, electrical circuits, and open flames. See Appendix G for more information about shut-off procedures.

2.3.2 Stop Oil Flow

Field personnel should determine the source of the discharge, and if safe to do so, immediately shut off the source of the discharge. Shut in the well(s) if necessary.

2.3.3 Stop the Spread of Oil and Call the Field Operations Manager

If safe to do so, field personnel must use resources available at the facility (see spill response material and equipment listed in Section 2.2) to stop the spilled material from spreading. Measures that may be implemented, depending on the location and size of the discharge, include placing sorbent material or other barriers in the path of the discharge (e.g., sand bags), or constructing earthen berms or trenches.

In the event of a significant discharge, field personnel must immediately contact the Field Operations Manager, who may obtain assistance from authorized company contractors and direct the response and cleanup activities. Should a discharge reach Big Bear Creek, only physical response and countermeasures should be employed, such as the construction of underflow dams, installation of hard boom and sorbent boom, use of sorbent pads, and use of vacuum trucks to recover oil and oily water from the creek. If water flow is low in the creek, construction of an underflow dam downstream and ahead of the spill flow may be advantageous. Sorbent material and/or boom should be placed immediately downstream of the dam to recover any sheen from the water. If water flow is normal in the creek, floating booms and sorbent boom will be deployed. Vacuum trucks will then be utilized to remove oil and oily water at dams and other access points. Crews should remove oiled vegetation and debris from the creek banks and place them in bags for later disposal. After removal of contaminated vegetation, creek banks should be flushed with water to remove free oil and help it flow down to dams and other access points where it can be recovered by vacuum truck. At no time shall any surfactants, dispersants, or other chemicals be used to remove oil from the creek.

2.3.4 Gather Spill Information

The Field Operations Manager will ensure that the *Discharge Notification Form* is filled out and that notifications have been made to the appropriate authorities. The Field Operations Manager may ask for assistance in gathering the spill information on the *Discharge Notification Form* (Appendix F) of this Plan:

- Reporter's name
- Exact location of the spill
- Date and time of spill discovery
- Material spilled (e.g., oil, produced water containing a reportable quantity of oil)
- Total volume spilled and total volume reaching or threatening navigable waters or adjoining shorelines
- Weather conditions
- Source of spill
- Actions being taken to stop, remove, and mitigate the effects of the discharge
- Whether an evacuation may be needed
- Spill impacts (injuries; damage; environmental media, e.g., air, waterway, groundwater)
- Names of individuals and/or organizations who have also been contacted

2.3.5 Notify Agencies Verbally

Some notifications must be completed *immediately* upon discovering the discharge. It is important to immediately contact the Field Operations Manager so that timely notifications can be made. If the Field Operations Manager is not available, or the Field Operations Manager requests it, field personnel must designate one person to begin notification. Section 2.1 of this Plan describes the required notifications to government agencies. The Notification List is included in Appendix F of this SPCC Plan. The Field Operations Manager must also ensure that written notifications, if needed, are submitted to the appropriate agencies.

2.4 Disposal Plan

The cleanup contractor will handle the disposal of any recovered product, contaminated soil, contaminated materials and equipment, decontamination solutions, sorbents, and spent chemicals collected during a response to a discharge incident.

Any recovered product that can be recycled will be placed into the gun barrel tank to be separated and recycled. Any recovered product not deemed suitable for on-site recycling will be disposed of with the rest of the waste collected during the response efforts.

If the facility responds to a discharge without involvement of a cleanup contractor, Clearwater will contract a licensed transportation/disposal company to dispose of waste according to regulatory requirements. The Field Operations Manager will characterize the waste and arrange for the use of certified waste containers.

All facility personnel handling hazardous wastes must have received both the initial 40-hour and annual 8-hour refresher training in the Hazardous Waste Operations and Emergency Response Standard (HAZWOPER) of the Occupational Health and Safety Administration (OSHA). This training is included as part of the initial training received by all field personnel. Training records and certificates are kept at the field office.

PART III. SPILL PREVENTION, CONTROL, AND COUNTERMEASURE PROVISIONS

40 CFR 112.7 and 112.9

3.1 Potential Discharge Volume and Direction of Flow [112.7(b)] and Containment [112.7(a)(3)(iii)]

Table 3-1, below, summarizes potential oil discharge scenarios. If unimpeded, oil would follow the site topography and reach Big Bear Creek.

Table 3-1: Potential discharge volume and direction of flow

Source	Type of failure	Maximum Volume (gal)	Maximum Discharge Rate (gal/hr)	Direction of Flow	Containment
Tank Battery					
Crude Oil Storage Tank	Rupture due to lightning strike, seam failure	16,800	16,800	Southeast towards Big Bear Creek.	Containment berm
	Leak at manway, valves	24	1	Southeast towards Big Bear Creek.	
	Overflow (1 day's production)	1,260	53	Southeast towards Big Bear Creek.	
Gun barrel	Rupture due to lightning strike, seam failure	21,000	21,000	Southeast towards Big Bear Creek.	Containment berm
	Leak at manway, valves	42	2	Southeast towards Big Bear Creek.	
	Overflow (1 day's production)	7,140	298	Southeast towards Big Bear Creek.	Containment berm
Flowlines and Piping					
Flowlines and Piping on Storage Tanks and Gun Barrel	Rupture/failure due to corrosion	3,570	148	Southeast towards Big Bear Creek.	Containment berm
	Pinhole leak, or leak at connection	48	2	Southeast towards Big Bear Creek.	
Flowlines and Piping associated with wells	Rupture/failure due to corrosion	3,570	148	Southeast towards Big Bear Creek.	None; See Oil Spill Contingency Plan

Source	Type of failure	Maximum Volume (gal)	Maximum Discharge Rate (gal/hr)	Direction of Flow	Containment
	Pinhole leak, or leak at connection	48	2	Southeast towards Big Bear Creek.	None; See Oil Spill Contingency Plan
Wells					
Polished rod stuffing box, valves, fittings, gauges	Leak	24	1	Southeast towards Big Bear Creek.	Well pad
Saltwater Disposal					
Piping/hoses, pumps, valves	Leak	24	1	Southeast towards Big Bear Creek.	Containment berm
Transfers and Loading Operations					
Transport truck loading hose	Rupture	84	84	Southeast towards Big Bear Creek.	Downslope berm
Offload line, connection	Leak	42	1	Southeast towards Big Bear Creek.	Downslope berm
Tank truck	Over-topping while loading	1,680	1,680	Southeast towards Big Bear Creek.	Drainage ditch
Transfer valve	Rupture, leak of valve packing	3	3	Southeast towards Big Bear Creek.	Load line container, curb

3.2 Containment and Diversionary Structures [112.7(c) and 112.7(a)(3)(iii)]

The facility is configured to minimize the likelihood of a discharge reaching navigable waters. The following measures are provided:

- Secondary containment for the oil storage tanks, saltwater tank (which may have small amounts of oil), and gun barrel is provided by a 60 ft x 40 ft x 2.5 ft earthen berm that provides a total containment volume of 867 barrels (36,423 gallons), as described in Section 3.2.2 below. The berm is constructed of native soils and heavy clay that have been compacted, then covered with gravel. A clay layer in the shallow subsurface exists naturally and will stop any spilled oil from seeping to deeper groundwater.

- The tank truck loading area is flat but gently slopes to the southeast, where a crescent-shaped, open berm has been placed to catch any potential spills from tanker transport trucks. The bermed area provides a catchment basin of 40 barrels (1,680 gallons), the maximum expected amount of a spill from the tanker due to overtopping of the truck during loading. In addition, the end of the load line is equipped with a load line drip bucket designed to prevent small discharges that may occur when disconnecting the hose.

- Booms, sorbents, shovels, and other discharge response materials are stored in a shed located in close proximity to the loading area. This material is sufficient to contain small discharges (up to approximately 200 gallons).

These measures are described in more details in the following sections.

3.2.1 Oil Production Facility Drainage [112.9(b)]

Facility drainage in the production/separation area but outside containment berms is designed to flow into drainage ditches located on the eastern and southern boundaries of the site. These ditches usually run dry. The ditches are visually examined by facility personnel on a daily basis during routine facility rounds, during formal monthly inspections, and after rain events, to detect any discoloration or staining that would indicate the presence of oil from small leaks within the facility. Any accumulation of oil is promptly removed and disposed off site. Formal monthly inspections are documented.

Discharges from ASTs are restrained by the secondary containment berm, as described in Section 3.2.2 of this Plan. Discharges occurring during transfer operations will be contained at each well by the rock pad or will flow into the drainage ditch located at the facility.

3.2.2 Secondary Containment for Bulk Storage Containers [112.9(c)(2)]

In order to further minimize the potential for a discharge to navigable waters, bulk storage containers such as all tank battery, separation, and treating equipment are placed inside a 2.5-ft tall earthen berm (fire wall). The berm capacity exceeds the SPCC and Louisiana requirements. It provides secondary containment sufficient for the size of the largest tank, plus at least 1 ft of freeboard to contain precipitation. This secondary containment capacity is equivalent to 173 percent of the capacity of the largest tank within the containment area (500 barrels) and exceeds the 10 percent freeboard recommended by API for firewalls around production tanks (API-12R1). The amount of freeboard also exceeds the amount of precipitation anticipated at this facility, which is estimated to average 3.5 inches for a 24-hour, 25-year storm, based on data from the nearby Ridgeview Regional Airport. Details of the berm capacity calculation are provided in Table 3-2.

Table 3-2: Berm capacity calculations

Berm Capacity	
Berm height	2.5 ft
Berm dimensions	60 ft x 40 ft = 2,400 ft^2
Tank footprint	4 tanks @ 12 ft dia. each = 4 x (π $12^2/4$) = 452 ft^2
Net volume	2.5 ft x (2,400 - 452) = 4,869 ft^3 = 36,423 gallons
Ratio to largest tank	36,423 / 21,000 = 173%
Corresponding Amount of Freeboard	
100% of tank volume	21,000 gallons = 2,807 ft^3
Net area (minus tank footprint)	2,400 ft^2 - 452 ft^2 = 1,948 ft^2
Minimum berm height for 100% of tank volume	2,807 ft^3 / 1,948 ft^2 = 1.44 ft
Freeboard	2.5 ft - 1.44 ft = 1.06 ft

The floor and walls of the berm are constructed of compacted earth with a layer of clay that ensures that the berm is able to contain the potential release of oil from the storage tanks until the discharge can be detected and addressed by field operations personnel. Facility personnel inspect the berm daily for the presence of oil. The sides of the berm are capped with gravel to minimize erosion.

The berm is equipped with a manual valve of open-and-closed design. The valve is used to drain the berm and is normally kept closed, except when draining water accumulation within the berm. Drainage from the berm flows into the drainage ditch to the south of the production/ separation area. All water is closely inspected by field operations personnel (who are the persons providing “responsible supervision”) prior to draining water accumulation to ensure that no free oil is present (i.e., there is no sheen or discoloration upon the surface, or a sludge or emulsion deposit beneath the surface of the water). The bypass valve for the containment structure is opened and resealed following drainage under the responsible supervision of field operations personnel. Free oil is promptly removed and disposed of in accordance with waste regulations. Drainage events are recorded on the form provided in Appendix D, including the time, date, and name of the employee who performed the drainage. The records are maintained with this SPCC Plan at the Ridgeview field office for a period of at least three years.

3.2.3 Practicability of Secondary Containment [112.7(d)]

Flowlines adjacent to the production equipment and storage tanks are located within the berm, and therefore have secondary containment. Aboveground flowlines that go from the wells to the production equipment and buried flowlines, however, lack adequate secondary containment.

The installation of double-wall piping, berms, or other permanent structures (e.g., remote impoundment) are impracticable at this facility due to the long distances involved and physical and road/fenceline right-of-way constraints. Additionally, such permanent structures would create land erosion and access problems for the landowner's farming operations and current uses of the land (e.g., agricultural production, animal grazing).

Other measures listed under 40 CFR 112.7(c) such as the use of sorbents are also impracticable as means of secondary containment since the volumes involved may exceed the sorbent capacity and the facility is attended for only a few hours each day.

Because secondary containment for flowlines outside of the tank battery is impracticable, Clearwater has provided with this Plan additional elements required under 40 CFR 112.7(d), including:

- A written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful (see Appendix H).
- An Oil Spill Contingency Plan following the provisions of 40 CFR 109 (see Appendix I).

3.3 Other Spill Prevention Measures

3.3.1 Bulk Storage Containers Overflow Prevention [112.9(c)(4)]

The tank battery is designed with a fail-safe system to prevent discharge, as follows:

- The capacity of the oil storage tanks is sufficient to ensure that oil storage is adequate in the event where facility personnel are unable to perform the daily visit to unload the tanks or the pumper is delayed in stopping production. The maximum capacity of the wells linked to the tank battery is approximately 600 barrels per day. The oil tanks are sized to provide sufficient storage for at least two days.

- The tanks are connected with overflow equalizing lines to ensure that a full tank can overflow to an adjacent tank.

3.3.2 Transfer Operations and Saltwater Disposal System [112.9(d)]

All aboveground valves and piping associated with transfer operations are inspected daily by the pumper and/or tank truck driver, as described in Section 3.4 of this Plan. The inspection procedure includes observing flange joints, valve glands and bodies, drip pans, and pipe supports. The conditions of the pumping well polish rod stuffing boxes, and bleeder and gauge valves, are inspected monthly.

Components of the produced water disposal system are inspected on a monthly basis by field operation personnel as described in Section 3.4 and following the checklist provided in Appendix C of this SPCC Plan. This includes the pumps and motors for working condition and leaks, hoses, valves, flowlines, and the saltwater injection wellhead. Maintenance and operation of the well itself and the downhole injection comply with EPA's and the state's Underground Injection Control (UIC) rules and regulations (40 CFR parts 144-148).

3.4 Inspections, Tests, and Records [112.7(e)]

This Plan outlines procedures for inspecting the facility equipment in accordance with SPCC requirements. Records of inspections performed as described in this Plan and signed by the appropriate supervisor are a part of this Plan, and are maintained with this Plan at the Ridgeview field office for a minimum of three years. The reports include a description of the inspection procedure, the date of inspection, whether drainage of accumulated rainwater was required, and the inspector's signature.

The program established in this SPCC Plan for regular inspection of all oil storage tanks and related production and transfer equipment follows the American Petroleum Institute's *Recommended Practice for Setting Maintenance, Inspection, Operation, and Repair of Tanks in Production Service* (API RP 12R1, Fifth Edition, August 1997). Each container is inspected monthly by field operation personnel as described in this Plan section and following the checklist provided in Appendix C of this SPCC Plan. The monthly inspection is aimed at identifying signs of deterioration and maintenance needs, including the foundation and support of each container. Any leak from tank seams, gaskets, rivets, and bolts is promptly corrected.

This Plan also describes provisions for monitoring the integrity of flowlines through a combination of monthly visual inspections and periodic pressure testing or through the use of an alternate technology. The latter element is particularly important for this facility since flowlines do not have adequate secondary containment.

The inspection program is comprised of informal daily examinations, monthly scheduled inspections, and periodic condition inspections. Additional inspections and/or examinations are performed whenever an operation alert, malfunction, shell or deck leak, or potential bottom leak is reported following a scheduled examination. Written examination/inspection procedures and monthly examination/inspection reports are signed by the field inspector and are maintained at the field office for a period of at least three years.

3.4.1 Daily Examinations

The facility is visited daily by field operations personnel. The daily visual examination consists of a walk through of the tank battery and around the wells. Field operations personnel check the wells and production equipment for leaks and proper operation. They examine all aboveground valves, polished rod stuffing boxes, wellheads, fittings, gauges, and flowline piping at the wellhead. Personnel inspect pumps to verify proper function and check for damage and leakage. They look for accumulation of water within the tank battery berms and verify the condition and position of valves. The storage tanks are gauged every day. A daily production report is maintained. All malfunctions, improper operation of equipment, evidence of leakage, stained or discolored soil, etc. are logged and communicated to the Clearwater Field Operations Manager.

Table 3-3: Scope of daily examinations

Facility Area	Item	Observations
Storage Tanks (Oil and Produced water)	Leaks	Tank liquid level gauged Drip marks, leaks from weld seams, base of tank Puddles containing spilled or leak material Corrosion, especially at base (pitting, flaking) Cracks in metal Excessive soil or vegetation buildup against base
	Foundation problems	Cracks Puddles containing spilled or leaked material Settling Gaps at base
	Flowlines problems	Evidence of leaks, especially at connections/collars Corrosion (pitting, flaking) Settling Evidence of stored material seepage from valves or seals
Wells	Leak	Evidence of oil seepage from pumping rod stuffing boxes, wellhead and wellhead flowlines, valves, gauges
SW Pumps	Leaks	Leaks at seals, flowlines, valves, hoses Puddles containing spilled or leaked material Corrosion

3.4.2 Monthly Inspections

Table 3-4 summarizes the scope of monthly inspections performed by field personnel.

The monthly inspection covers the wellheads, flowlines, and all processing equipment. It also includes verifying the proper functioning of all detection devices, including high-level sensors on oil storage tanks, heater treater, and separators. Storage tanks are inspected for signs of deterioration, leaks, or accumulation of oil inside the containment area, or other signs that maintenance or repairs are needed. The secondary containment area is checked for proper drainage, general conditions, evidence of oil, or signs of leakage. The monthly inspection also involves visually inspecting all aboveground valves and pipelines and noting the general condition of items such as transfer hoses, flange joints, expansion joints, valve glands and bodies, catch pans, pipeline supports, pumping well pumping rod stuffing boxes, bleeder and gauge valves, locking of valves, and metal surfaces.

The checklist provided in Appendix C is used during monthly inspections. These inspections are performed in accordance with written procedures such as API standards (e.g., API RP 12R1), engineering specifications, and maintenance schedule developed by the equipment manufacturers.

All safety devices are tested quarterly by a third party inspector. The tests are recorded and the results are maintained with this Plan at Clearwater's field office. Testing of the safety devices is conducted in accordance with guidelines API RP-14C published by the American Petroleum Institute, or in accordance with instructions from the device's manufacturer. Written test procedures are kept at the offices of the third party testing company and are available upon request.

Twice a year, facility personnel drive to the pre-established response staging areas located at three different points along Big Bear Creek (see Oil Spill Contingency Plan in Appendix I) to ensure that the dirt/gravel roads are accessible using field vehicles and that the Oil Spill Contingency Plan can be implemented in the event of a discharge from flowlines reaching the Creek.

Table 3-4: Scope of monthly inspections

Facility Area	Equipment	Inspection Item
Tank Battery	Storage tanks	Leakage, gaskets, hatches Tank liquid level checked Tank welds in good condition Vacuum vents Overflow lines Piping, valves, and bull plugs Corrosion, paint condition Pressure / level safety devices* Emergency shut-down system(s)* Pressure relief valves*
	Area	Berm and curbing Presence of contaminated/stained soil Excessive vegetation Equipment protectors and signs Engine drip pans and sumps General housekeeping
Truck Loading	Offload lines, drip pans, valves, catchment berm	Valve closed and in good condition Cap or bull plug at end of offload line/connection Sign of oil or standing water in drip pan(s) Sign of oil or standing water in catchment berm Sign of oil in surrounding area
	Production equipment	Gauges (pressure, temperature, and liquid level) Pressure / level safety devices* Emergency shut-down system(s)* Pressure relief valves*
Wells (including saltwater disposal well)	Area	Spills and leaks (e.g., stuffing box) Equipment protectors and signs General housekeeping

Facility Area	Equipment	Inspection Item
Leasehold area between wells and Tank Battery	Flowlines	Flowline between the well and tank battery/gun barrel Exposed line of buried piping Valves (condition of, whether locked or sealed) Evidence of leaks and/or damage, especially at connections/collars Corrosion (pitting, flaking) Pipe supports
	Road and Field Ditches	Evidence/puddles of crude oil and/or produced water
Other	Chemicals, Fuels and Lube Oils	Storage conditions
Response staging areas	Area	Road practicable by field vehicle Area clear of excessive vegetation
* Tested quarterly by third party inspection company.		

3.4.3 Periodic Condition Inspection of Bulk Storage Containers

A condition inspection of bulk storage containers is performed by a qualified inspector according to the schedule and scope specified in API RP 12R1. The schedule is determined based on the corrosion rate; with the first inspection performed no more than 15 years after the tank construction, as detailed in Table 3-5.

Three bulk storage containers installed at this facility were moved from another facility decommissioned by Clearwater. These bulk storage containers were leak tested after relocation to the facility.

Table 3-5: Schedule of periodic condition inspection of bulk storage containers

Tank	Year Built	Last Inspection	Next inspection by
#1	1983	11/5/1998	11/5/2008*
#2	2002	None	First inspection to be performed by 12/31/2017*
#3	1995	None	First inspection to be performed by 12/31/2010*
#4	2002	None	First inspection to be performed by 12/31/2017*
#5	1991	None	First inspection to be performed by 12/31/2006*

* Dates for subsequent external inspections must follow the recommendations of the certified inspector, not to exceed three-quarters of the predicted shell/roof deck corrosion rate life, or maximum of 15 years.

3.4.4 Brittle Fracture Evaluation [112.7(i)]

At the present time, none of the bulk storage containers at this site was field-erected, and therefore no brittle fracture evaluation is required.

3.4.5 Flowline Maintenance Program [112.9(d)(3)]

Because the facility is relying on a contingency plan to address discharges, the flowline maintenance program is specifically implemented to maintain the integrity of the primary container (in this case piping) to minimize releases of oil from this part of the production facility. The facility's gathering lines and flowlines are configured, inspected monthly for leaks at connections and on each joint, corrosion (pitting, flaking), and maintained to minimize the potential for a discharge as summarized in Table 3-6. Records of integrity inspections, leak tests, and part replacements are kept at the facility for at least three years (integrity test results are kept for ten years).

Table 3-6: Components of flowline maintenance program

Component	Measures/Activities
Configuration	• Well pumps are equipped with low-pressure shut-off systems that detect pressure drops and minimize spill volume in the event of a flowline leak. • Flowlines are identified on facility maps and are marked in the field to facilitate access and inspection by facility personnel. Flowline maps and field tags indicate the location of shutdown devices and valves that may be used to isolate portions of the flowline. • With the exception of a portion of Flowline B under an access road, the flowlines and appurtenances (valves, flange joints, supports) can be visually observed for signs of leakage, deterioration, or other damage.
Inspection	• Lines are visually inspected for leaks and corrosion as part of the monthly rounds by field personnel, as discussed in Section 3.4 above. • The buried portions of Flowline B are coated/wrapped and visually observed for damage or coating condition whenever they are repaired, replaced, or otherwise exposed. • Every five years, flowlines are tested using ultrasonic techniques to determine remaining wall thickness and mechanical integrity. Copies of test results are maintained at the facility for ten years to allow comparison of successive tests.
Maintenance	• Any leak in the flowline or appurtenances is promptly addressed by isolating the damaged portion and repairing or replacing the faulty piece of equipment. Clearwater does not accept pipe clamps and screw-in plugs as forms of repair. • Any portion of a flowline that fails the mechanical integrity test is repaired and retested, or replaced.

3.5 Personnel, Training, and Discharge Prevention Procedures [112.7(f)]

The Field Operations Manager has been designated as the point of contact for all oil discharge prevention and response at this facility.

All Clearwater field personnel receive training on proper handling of oil products and procedures to respond to an oil discharge prior to entering any Clearwater production facility. The training ensures that all facility personnel understand the procedures described in this SPCC Plan and are informed of the requirements under applicable pollution control laws, rules and regulations. The training also covers risks associated with potential exposure to hydrogen sulfide (H_2S) gas.

All Clearwater field personnel also receive an initial 40-hour HAZWOPER training (and 8-hour annual refresher training) as per OSHA standard.

Clearwater ensures that all contractor personnel are familiar with the facility operations, safety procedures, and spill prevention and control procedures described in this Plan prior to working at the facility. All contractors working at the facility receive a copy of this SPCC Plan. Avonlea personnel visiting the facility receive training similar to that provided to Clearwater oil handling employees.

Clearwater management holds briefings with field operations personnel (including contractor personnel as appropriate) at least once a year, as described below.

3.5.1 Spill Prevention Briefing

The Field Operations Manager conducts Spill Prevention Briefings annually to ensure adequate understanding and effective implementation of this SPCC Plan. These briefings highlight and describe known spill events or failures, malfunctioning components, and recently developed precautionary measures. The briefings are conducted in conjunction with the company safety meetings. Sign-in sheets, which include the topics of discussion at each meeting, are maintained with this Plan at Clearwater's field office. A *Discharge Prevention Briefing Log* form is provided in Appendix E to this Plan and is used to document the briefings. The scheduled annual briefing includes a review of Clearwater policies and procedures relating to spill prevention, control, cleanup, and reporting; procedures for routine handling of products (e.g., loading, unloading, transfers); SPCC inspections and spill prevention procedures; spill reporting procedures; spill response; and recovery, disposal, and treatment of spilled material.

Personnel are instructed in operation and maintenance of equipment to prevent the discharge of oil, and in applicable federal, state, and local pollution laws, rules, and regulations. Facility operators and other personnel have an opportunity during the briefings to share recommendations concerning health, safety, and environmental issues encountered during facility operations.

The general outline of the briefings is as follows:

- Responsibilities of personnel and Designated Person Accountable for Spill Prevention;
- Spill prevention regulations and requirements;
- Spill prevention procedures;
- Spill reporting and cleanup procedures;
- History/cause of known spill events;
- Equipment failures and operational issues;
- Recently developed measures/procedures;
- Proper equipment operation and maintenance; and
- Procedures for draining rainwater from berms.

3.5.2 Contractor Instructions

In order that there will be no misunderstanding on joint and respective duties and responsibilities to perform work in a safe manner, contractor personnel also receive instructions on the procedures outlined in this SPCC Plan. The instructions cover the contractor activities such as servicing a well or equipment associated with the well, such as pressure vessels.

All contractual agreements between Clearwater and contractors specifically state:

> Personnel must, at all times, act in a manner to preserve life and property, and prevent pollution of the environment by proper use of the facility's prevention and containment systems to prevent hydrocarbon and hazardous material spills. No pollutant, regardless of the volume, is to be disposed of onto the ground or water, or allowed to drain into the ground or water. Federal regulations impose substantial fines and/or imprisonment for willful pollution of navigable waters. Failure to report accidental pollution at this facility, or elsewhere, can be cause for equally severe penalties to be imposed by federal regulations. To this end, all personnel must comply with every requirement of this SPCC Plan, as well as taking necessary actions to preserve life, and property, and to prevent pollution of the environment. It is the contractor's (or subcontractor's) responsibility to maintain his equipment in good working order and in compliance with this SPCC Plan. The contractor (or subcontractor) is also responsible for the familiarity and compliance of his personnel with this SPCC Plan. Contractor and subcontractor personnel must secure permission from Clearwater's Field Operations Manager before commencing any work on any facility. They must immediately advise the Field Operations Manager of any hazardous or abnormal condition so that the Field Operations Manager can take corrective measures.

APPENDIX A: Facility Diagrams

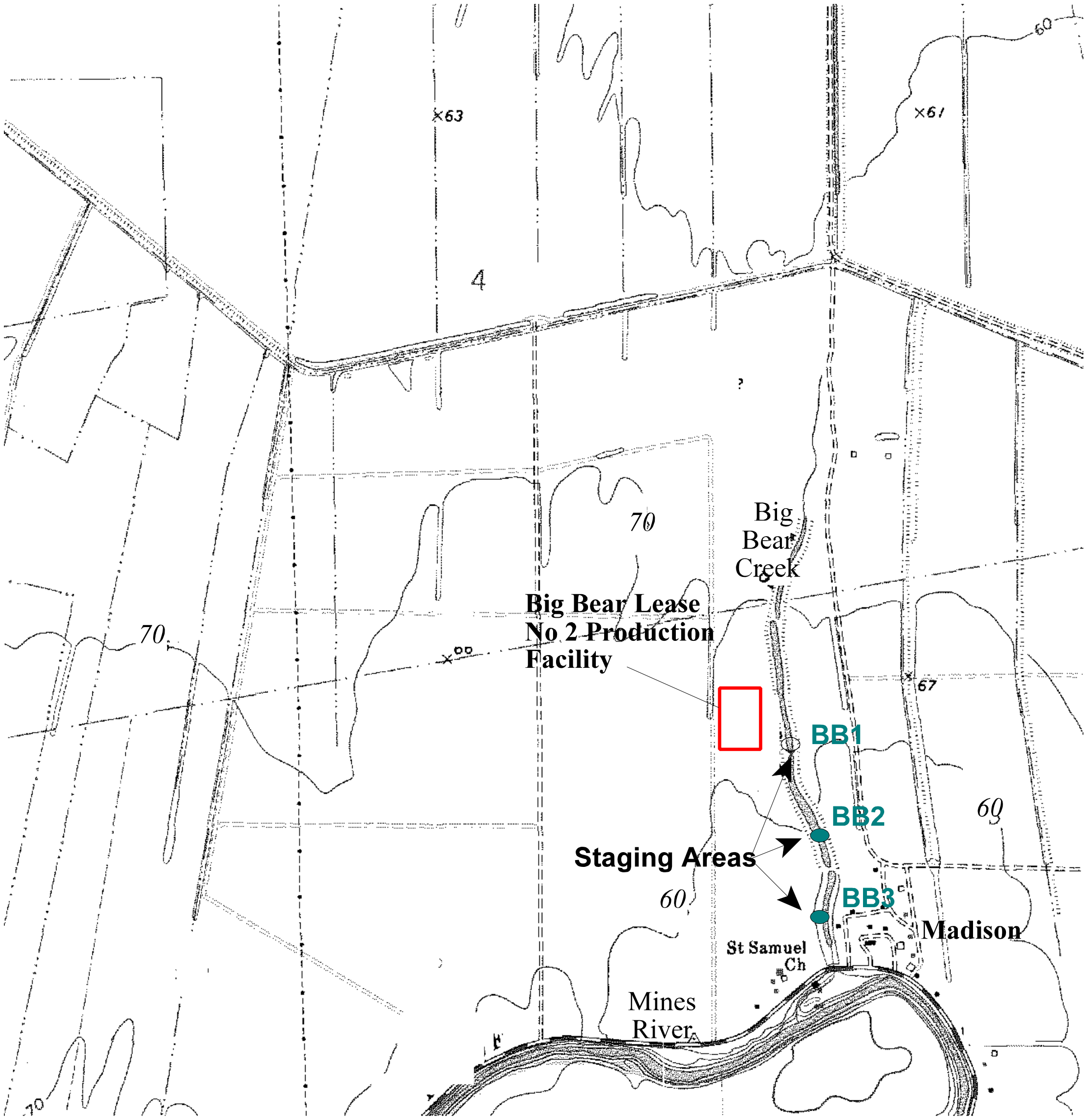

Figure A-1: Site plan.

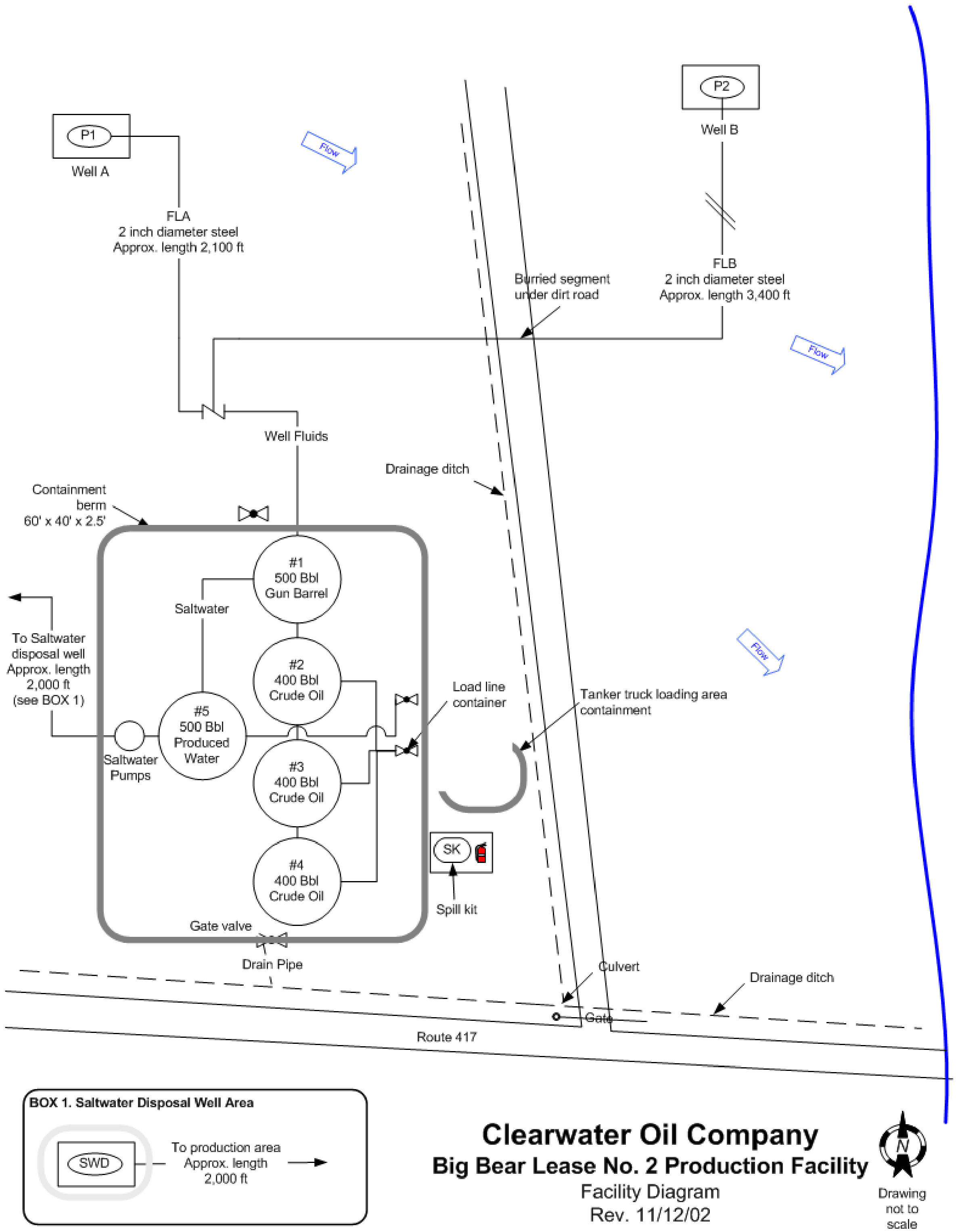

Figure A-2: Production Facility Diagram.

APPENDIX B: Tank Truck Loading Procedures

Loading Tank Truck

Make sure the vehicle tank is properly vented before starting to load or unload. If you are not certain that the trailer is properly vented, you must contact your supervisor and request permission to open the trailer dome before starting to load or unload.

To Load from Storage Tank to Tank Truck

- Attach ground cable or bonding clamp to trailer.
- Use wheel chocks or other similar barrier to prevent premature departure.
- Hook up load hose and open all appropriate valves from storage tank to trailer entry.
- Disengage clutch and place pump in load position.
- Release clutch slowly.
- Adjust throttle to proper engine RPM.
- When trailer is loaded to appropriate level, slow engine speed.
- Close valve to storage tank.
- Loosen loading hose to allow enough air to drain loading hose dry.
- Ensure that drips from the hose drain into the spill bucket at the loading area.
- Disconnect loading hose completely, close load valve, plug and fasten securely.
- Close belly valve on trailer.
- Disconnect ground cable.
- Promptly clean up any spilled oil.
- Inspect lowermost drains and valves of the vehicle for discharges/leaks and ensure that they are tightened, adjusted, or replaced as needed to prevent discharges while vehicle is in transit.

APPENDIX C: Monthly Inspection Checklist

Further description and comments, if needed, should be provided on a separate sheet of paper and attached to this sheet. Any item answered "YES" needs to be promptly reported, repaired, or replaced, as it may result in non-compliance with regulatory requirements. Records are maintained with the SPCC Plan at the Ridgeview field office.

Date: _________________ Signature: ____________________________

	Yes	No	Description & Comments (Note tank/equipment ID)
Storage tanks and Separation Equipment			
Tank surfaces show signs of leakage			
Tanks show signs of damage, rust, or deterioration			
Bolts, rivets or seams are damaged			
Aboveground tank supports are deteriorated or buckled			
Aboveground tank foundations have eroded or settled			
Gaskets are leaking			
Level gauges or alarms are inoperative			
Vents are obstructed			
Thief hatch and vent valve does not seal air tight			
Containment berm shows discoloration or stains			
Berm is breached or eroded or has vegetation			
Berm drainage valves are open/broken			
Tank area clear of trash and vegetation			
Equipment protectors, labels, or signs are missing			
Piping/Flowlines and Related Equipment			
Valve seals or gaskets are leaking.			
Pipelines or supports are damaged or deteriorated.			
Buried pipelines are exposed.			
Transfer equipment			
Loading/unloading lines are damaged or deteriorated.			
Connections are not capped or blank-flanged			
Secondary containment is damaged or stained			
Response Kit Inventory			
Discharge response material is missing or damaged or needs replacement			

Additional Remarks (attach sheet as needed):

APPENDIX D: Record of Dike Drainage

This record must be completed when rainwater from diked areas is drained into a storm drain or into an open watercourse, lake, or pond, and bypasses the water treatment system. The bypass valve must normally be sealed in closed position and opened and resealed following drainage under responsible supervision. Records are maintained with the SPCC Plan at the Ridgeview field office.

Date	**Area**	**Presence of Oil**	**Time Started**	**Time Finished**	**Signature**
12/5/2003	Tank battery	No oil	08:00	8:40	William Mackenzie

APPENDIX E: Discharge Prevention Briefing Log

Date	Type of Briefing	Instructor(s)
12/5/2003	Scheduled refresher. All field personnel.	Helena Berry, Optimal H&S Inc.
11/25/2004	Scheduled refresher. All field personnel.	Bill Laurier

APPENDIX F: Discharge Notification Procedures

Circumstances, instructions, and phone numbers for reporting a discharge to the National Response Center and other federal, state, and local agencies, and to other affected parties, are provided below. They are also posted at the facility in the storage shed containing the discharge response equipment. Note that any discharge to water must be reported immediately to the National Response Center.

Field Operations Manager, Bill Laurier (24 hours)	(405) 829-4051
Local Emergency (fire, explosion, or other hazards)	911

Agency / Organization	Agency Contact	Circumstances	When to Notify
Federal Agencies			
National Response Center	1-800-424-8802	Discharge reaching navigable waters.	**Immediately (verbal)**
EPA Region VI (Hotline)	1-800-887-6063		**Immediately (verbal)**
EPA Region VI Regional Administrator	First Interstate Bank Tower at Fountain Place 1445 Ross Avenue, 12th floor, Suite 1200 Dallas TX 75202	Discharge 1,000 gallons or more; or second discharge of 42 gallons or more over a 12-month period.	Written notification within 60 days (see Section 2.1 of this Plan)
State Agencies			
Office of State Police, Transportation and Environmental Safety Section, Hazardous Materials Hotline	225-925-6595 or 1-877-925-6595	1) Injury requiring hospitalization or fatality. 2) Fire, explosion, or other impact that could affect public safety. 3) Release exceeding 24-hour reportable quantity. 4) Impact to areas beyond the facility's confines.	**Immediately (verbal)** Written notification to be made within 5 days.
Office of State Police, Transportation and Environmental Safety Section, Hazardous Materials Hotline	225-925-6595 or 1-877-925-6595	Discharges that pose emergency conditions, regardless of the volume discharged.	**Within 1 hour** of discovery (verbal). Written notification within 7 working days.
Louisiana Department of Environmental Quality, Office of Environmental Compliance	225-763-3908 or 225-342-1234 (after business hours, weekends and holidays)	Discharges that do not pose emergency conditions.	Within 24 hours of discovery (verbal). Written notification within 7 working days.

Agency / Organization	Agency Contact	Circumstances	When to Notify
Local Agencies			
St. Anthony's Parish Emergency Planning Committee	337-828-1960	Any discharge of 100 lbs or more that occur beyond the boundaries of the facility, including to the air.	**Immediately (verbal)** Written notification within 7 days.
Others			
Response/cleanup contractors	EZ Clean (800) 521-3211 Armadillo Oil Removal Co. (214) 566-5588	Any discharge that exceeds the capacity of facility personnel to respond and cleanup.	As needed
Howard Fleming Farm (agricultural irrigation intake)	(405) 235-6893	Any discharge that threatens to affect neighboring properties and irrigation intakes.	As needed

The person reporting the discharge must provide the following information:

- Name, location, organization, and telephone number;
- Name and address of the owner/operator;
- Date and time of the incident;
- Location of the incident;
- Source and cause of discharge;
- Types of material(s) discharged;
- Total quantity of materials discharged;
- Quantity discharged in harmful quantity (to navigable waters or adjoining shorelines);
- Danger or threat posed by the release or discharge;
- Description of all affected media (e.g., water, soil);
- Number and types of injuries (if any) and damaged caused;
- Weather conditions;
- Actions used to stop, remove, and mitigate effects of the discharge;
- Whether an evacuation is needed;
- Name of individuals and/or organizations contacted; and
- Any other information that may help emergency personnel respond to the incident.

Whenever the facility discharges more than 1,000 gallons of oil in a single event, or discharges more than 42 gallons of oil in each of two discharge incidents within a 12-month period, the Manager of Field Operations must provide the following information to the U.S. Environmental Protection Agency's Regional Administrator within 60 days:

- Name of the facility;
- Name of the owner or operator;
- Location of the facility;

- Maximum storage or handling capacity and normal daily throughput;
- Corrective actions and countermeasures taken, including a description of equipment repairs and replacements;
- Description of facility, including maps, flow diagrams, and topographical maps;
- Cause of the discharge(s) to navigable waters, including a failure analysis of the system and subsystems in which the failure occurred;
- Additional preventive measures taken or contemplated to minimize possibility of recurrence; and
- Other pertinent information requested by the Regional Administrator.

Discharge Notification Form

*** Notification must not be delayed if information or individuals are not available.

Facility: Clearwater Oil Company Big Bear Lease No. 2 Production Facility
5800 Route 417, Madison, Louisiana 73506

Description of Discharge		
Date/time	Release date: Release time: Duration:	Discovery date: Discovery time:
Reporting Individual	Name: Tel. #:	
Location of discharge	Latitude: Longitude:	Description:
Equipment source	☐ piping ☐ flowline ☐ well ☐ unknown ☐ stock, flare	Description: Equipment ID:
Product	☐ crude oil ☐ saltwater ☐ other*	* Describe other:
Appearance and description		
Environmental conditions	Wind direction: Wind speed:	Rainfall: Current:
Impacts		
Quantity	Released:	Recovered:
Receiving medium	☐ water** ☐ land ☐ other (describe):	☐ Release confined to company property. ☐ Release outside company property. ** If water, indicate extent and body of water:
Describe circumstances of the release		
Assessment of impacts and remedial actions		
Disposal method for recovered material		
Action taken to prevent incident from reoccurring		
Safety issues	☐ Injuries ☐ Fatalities ☐ Evacuation	

Notifications		
Agency	**Name**	**Date/time reported & Comments**
Company Spill Response Coordinator		
National Response Center 1-800-424-8802		
State police		
Parish Emergency Response Commission		
oil spill removal organization/cleanup contractor		

APPENDIX G: Equipment Shut-off Procedures

Source	**Action**
Manifold, transfer pumps or hose failure	Shut in the well supplying oil to the tank battery if appropriate. Immediately close the header/manifold or appropriate valve(s). Shut off transfer pumps.
Tank overflow	Shut in the well supplying oil to the tank battery. Close header/manifold or appropriate valve(s)
Tank failure	Shut in the well supplying oil to the tank battery. Close inlet valve to the storage tanks.
Flowline rupture	Shut in the well supplying oil to the flowline. Close nearest valve to the rupture site to top the flow of oil.
Flowline leak	Shut in the well supplying oil to the flowline. Immediately close the nearest valve to stop the flow of oil to the leaking section.
Explosion or fire	Immediately evacuate personnel from the area until the danger is over. Immediately shut in both wells if safe to do so. If possible, close all manifold valves. If the fire is small enough such that it is safe to do so, attempt to extinguish with fire extinguishers available on site.
Equipment failure	Immediately close the nearest valve to stop the flow of oil into the leaking area.

APPENDIX H: Written Commitment of Manpower, Equipment, and Materials

In addition to implementing the preventive measures described in this Plan, Clearwater will also specifically:

- In the event of a discharge:
    - Make available all trained field personnel (three employees) to perform response actions
    - Obtain assistance from an additional three full-time employees from its main operations contractor (Avonlea Services)
    - Collaborate fully with local, state, and federal authorities on response and cleanup operations
- Maintain all on-site oil spill control equipment described in this Plan and in the attached Oil Spill Contingency Plan. The equipment is estimated to contain oil spills of up to 500 gallons.
- Maintain all communications equipment in operating condition at all times.
- Ensure that staging areas to be used in the event of a discharge to Big Bear Creek are accessible by field vehicles.
- Review the adequacy of on-site and third-party response capacity with pre-established response/cleanup contractors on an annual basis and update response/cleanup contractor list as necessary.
- Maintain formal agreements/contracts with response and cleanup contractors who will provide assistance in responding to an oil discharge and/or completing cleanup (see contract agreements maintained separately at the Ridgeview field office and lists of associated equipment and response contractor personnel capabilities).

Authorized Facility Representative:	Bill Laurier
Signature:	*Bill Laurier*
Title:	Field Operations Manager

APPENDIX I: Oil Spill Contingency Plan

The oil spill contingency plan is maintained separately at the Ridgeview field office.

[Refer to the sample Contingency Plan also available from EPA for more information on the content and format of that Plan]

Osage Form 208 (2002)

UNITED STATES
DEPARTMENT OF THE INTERIOR
OSAGE AGENCY
P.O. Box 1539
Pawhuska, Oklahoma 74056
Report of Completed & Deepened Wells Within the Osage Reservation

160 Acres

↑ N

Spot well on Plat

Specify type of well
Oil, Gas, CBM,SWD, Dry, etc.________

One original must be filed within 10 days after completion of well.

Company operating ____________ Address ____________

Lessee ____________ Lessor **OSAGE TRIBE**

Well No.______ ¼ Sec.______ Twp.______ Rge.______ Farm name ____________

Well located ________ ft from [N] [S] line, ________ [E] [W] line, Elevation GL________ DF________ KB________

Elevation and location surveyed by ____________

Drilling contractor(s) ____________ Began ________, 20____ Finished ________, 20____

Cable drilled interval and bit size(s) ____________

Mud ☐ Air ☐ Rotary drilled interval & bit size(s) ____________

Casing Record | Cementing Contractor ____________

Size	Wt.	Landed at	Interval cemented		Cement used; include type, gel, additives
______ ins.	______ lbs./ft.	______ ft.	______	to ______	____________
______ ins.	______ lbs./ft.	______ ft.	______	to ______	____________
______ ins.	______ lbs./ft.	______ ft.	______	to ______	____________

Interval(s) perforated ____ holes ________ to ____; ____ holes ________ to ____; ____ holes ________ to ____

Interval(s) left open ____________; Interval(s) shut off and method ____________

Plug back depth ________ Packer set? ________ Setting depth ________ Packer left in? ________

How were fresh water and other zones protected? ____________

Flow ☐ Pump ☐ Swab ☐ Bail ☐ **Initial 24 hour Production Rate Before Treatment**

Casing ☐ Tubing ☐ Choke size ________ Oil ________ bbls., Gas ________ MCF, Water ________ bbls

Duration of test ______ hrs., Gravity ____ API FTP ______ psi SICP ______ psi SITP ______ psi

Formation treatment (shot, acid, fracture, etc.) Indicate amount of materials used (i.e., nitro, sand, water, acid, & other additives) and breakdown pressure.

____________ ________ Feet to ________

____________ ________ Feet to ________

____________ ________ Feet to ________

Flow ☐ Pump ☐ **Initial 24 hour Production Rate After Treatment and Recovery of Load**

Casing ☐ Tubing ☐ Choke size ________ Oil ________ bbls., Gas ________ MCF, Water ________ bbls

Duration of test ______ hrs., Gravity ____ API FTP ______ psi SICP ______ psi SITP ______ psi

Location fee paid ____________ Date ____________ Amount $ ________

Signature ____________ Position with Lessee ____________

_______ ¼ Sec_________ T _____________ R _____________ Datum Elev.___________________

FORMATION RECORD

Well Number____

FROM	TO	FEET	Note each change in formation, i.e., sand, lime shale, sandy shale, etc. & name key beds. Note character of each formation, i.e., color, hard, soft, caving, etc. Underreamed? Note contents of each formation, i.e., oil, gas, water, and kind of water – fresh, etc.
Surface			Must run and submit open hole logs sufficient to
			determine resistivity and porosity of all formations.
			Cased hole logs sufficient to correlate with
			open hole logs and determine cement bond
			quality.
			Was well cored ______, enter core description,
			submit core analysis.
			Copies of cementing service tickets should
			accompany this report.
			Include drill stem, wire line, etc.
			test information.

Osage Form No. 139 (1991)

UNITED STATES
DEPARTMENT OF THE INTERIOR
P.O. BOX 1539
PAWHUSKA, OKLAHOMA 74056

Date ______________

APPLICATION FOR OPERATION OF REPORT ON WELLS

(Commencement money paid to whom) (Date) (Amount)

Well No.______ is located _________ ft. from {N / S} line and _________ ft. from {E / W} line.

______________ ______________ ______________ Osage County, Oklahoma.
(1/4 Section & Section No.) (Township) (Range)

The elevation of the {surface / derrick floor} above sea level is ________ ft.

USE THIS SIDE TO REQUEST AUTHORITY FOR WORK

Notice of intention to:

- Drill ☐
- Plug ($15 fee required) ☐
- Deepen or plug back ☐
- Convert ☐
- Pull or alter casing ☐
- Formation treatment ☐
- .... ☐

Details of Work

Drilling application will state proposed TD & Horizons to be tested. Show size & length of casings to be used. Indicate proposed mudding, cementing & other work. Plugging applications shall set forth reasons for plugging & detailed statement of proposed work.

Plugging will not commence until 10 days following approval date unless authority granted for earlier commencement.

A $15.00 plugging fee is also required with each application to plug.

Well production prior to work.
__________ bbls. oil ________ bbls. wtr./24 hrs.

I understand that this plan of work must receive approval in writing of the Osage Indian Agency before operations may be commenced.

Lessee: ______________

Signature: ______________

Title: ______________

Address: ______________

Telephone: ______________

USE THIS SIDE TO REPORT COMPLETED WORK

(one copy required)

Character of well (Whether oil, gas or dry) ______________

Subsequent report of:

- Conversion ☐
- Formation treatment ☐
- Altering casing ☐
- Plugging back ☐
- Plugging ☐

Details of Work & Results Obtained

Work commenced ______________ 20 ___
Work completed ______________ 20 ___
(Continue on reverse side if necessary)

This block for plugging information only

CASING RECORD

Size	In hole when started	Amount recovered	If parted Depth	How
ORIGINAL TOTAL DEPTH				

Lessee: ______________

By: ______________
Signature

Subscribed and sworn to before me this day ______________
of ______________ 20______

____
Notary Public

My commission expires ______________

Appendix C

Injection Well Engineering Evaluation

How does EPA determine the rate of accumulation?

The rate of accumulation (or "net" injection rate) relates to the volume of injected fluids that over a number of days fails to reach the producing wells in an enhanced oil recovery project. In this type of project the "net" injection rate for a well, or group of wells, may be lower than the injection rate measured at the wellhead (the "gross" injection rate). In disposal operations, on the other hand, all of the injected fluids remain in the reservoir.

- **(a)** The pressure build up created in the reservoir by the accumulation of injected fluids must not result in the movement of fluids into a USDW.
- **(b)** For a given period of operation, the estimated rate of accumulation of injected fluids is a function of a number of variables. Some of these variables are the result of decisions made by the operators and some are intrinsic to the reservoir.

How does EPA evaluate the reservoir flow system?

The analysis of a reservoir flow system usually starts by reviewing maps for the area of interest. In the Osage UIC program, the type of map most frequently available to the engineer is the location (plat) map.

The location map provides, at a minimum, visual information on the well population and distribution. These two important factors have great potential for impacting the reservoir flow pattern and, by default, the allowable rate of accumulation for a given period of operation. The information on the provided map is usually complemented with other information from the application package to establish the number of improperly completed and improperly plugged and abandoned (P&A'd) wells. It is equally important that the map identify the type of each remaining well in the area under study.

Why do is it important to determine points with endangerment potential?

Points with potential for endangerment within a study area are those locations where injected fluids could migrate from the injection zone into USDWs. The most frequently found avenues for the vertical movement of injected fluids into USDWs are improperly completed or plugged wells. Appendix B of this section illustrates, with well schematics, the requirements for proper plugging and abandoning wells. It is very likely that the larger the number of injection wells in a given reservoir, the lower the environmentally safe rate of accumulation for each well if all other variables remain the same.

How do we define an improperly completed well?

A well is considered improperly completed if:

- **a.** Surface casing cement not circulated;
- **b.** Surface casing cemented but not set at least 50 feet below the base of USDWs;
- **c.** Production casing not cemented;
- **d.** Top of production casing cement less than 100 feet above the top of the injection interval; or,
- **e.** There is un-cemented casing opposite injection zones in neighboring wells.

How do we define an improperly plugged and abandoned (P&A'd) well ?

A well is considered to be improperly plugged and abandoned by EPA if:

- **a.** Open hole filled only with mud and debris;
- **b.** Production casing ripped above the top of cement, pulled, and the hole is filled with mud;
- **c.** Cement plugs placed inside un-cemented surface or production casing;
- **d.** Cement plugs improperly located or sized; or
- **e.** No information is provided on the plugging procedure.

A permit to plug must be obtained from BIA prior to plugging. BIA must also witness the plugging. Within ten days after plugging, a report must be filed with the BIA Superintendent. **See 25 CFR Section 226.18 and 226.29 for applicable requirements.**

How is the Base of USDW estimated?

The permitted rate of accumulation for two wells with identical completion and reservoir characteristics would differ if the depth to the base of the USDWs were different. The well with a deeper USDW depth would be permitted at a lower rate of accumulation. Two approaches are often used to determine the USDW.

Fresh Water Supply Well Inventory - The reviewer may search a database of information on the ownership, location and completion of private fresh water supply wells in Osage County, Oklahoma. The information in this database can provide insight into the depth of fresh water sands in a study area. Though it is not certain that the depth information may correspond to the base of the USDWs, it may prove valuable in assessing endangerment risk in the absence of any other data.

Alternatively, an Approximate Empirical Approach may be used. Ideally, an electric log run through the fresh water sands will be available for the well of interest. If such log is not available, the reviewer may use a log from the proposed injection well (preferred) or a neighboring well to estimate the depth of the base of USDWs.

How is the Reservoir Pressure determined?

The estimated rate of accumulation will be lower for the well with the larger reservoir pressure, if remaining parameters are identical. The permits team usually performs estimates of the reservoir pressure using field data. The following illustrates some of the sources for these data.

> **Fluid Level Data** – A fluid level measurement is used to estimate the reservoir pressure at that location. Field staff measure the fluid level in a well using an echometer after the well has been shut in long enough to approach static conditions. If the fluid level is obtained before the well has stabilized, the reservoir pressure and rate of accumulation estimates will be in error.
>
> **Well Transient Test Data** - The reservoir pressure can be estimated from well test data such as that gathered through fall off, build up or drill stem tests. This information can also be used to estimate the reservoir permeability.

Why are estimating Formation Absolute Permeability, Porosity and Effective Thickness important?

Permeability, porosity and thickness are reservoir intrinsic properties that greatly affect the amount of produced water which can be injected into the formation. The more permeable a rock, the greater its ability to accumulate fluids for a given limiting pressure increment and over a given period of operation.

The reservoir effective thickness is primarily a function of the rock's permeability and of the perforated interval. If a well has been cased and cemented, the effective thickness may be changed when perforations are added or squeezed. Sources of information the UIC permitting engineers explore to obtain the needed permeability, porosity and thickness information.

Laboratory Core Analysis Reports - Core analysis reports usually provide information on permeability determined for core plugs that have been fully saturated with fluid. The reported values are generally regarded as the absolute permeability for the sampled interval, usually one foot thick.

Well Transient Test Information - It is common practice in reservoir evaluation to use some widely approved engineering methods to estimate permeability using information (pressure, fluid flow, elapsed time, etc.) gathered by conducting well transient tests. The permeability estimated by these means may have been a function of the saturation of a given fluid in the reservoir at the time of the test (i.e., relative permeability).

How does Water Viscosity vary?

Water viscosity is generally assumed to be one centipoises. However, viscosity changes with reservoir characteristics. Water viscosity can be estimated as a function of temperature and pressure using empirical correlations. Information on the water salinity or Total Dissolved Salts (TDS) will also be needed.

What is the Zone Of Endangering Influence (ZEI)?

After the permits engineer has gathered and validated information for all necessary variables, an analysis of the reservoir pressure response is prepared. The pressure response of interest is affected by the accumulation of fluids in the injection zone during a pre-defined period of operation.

The Osage UIC program estimates pressures generated by the injection activity at certain distances from the injection point(s) using simple algebraic expressions. One expression applies to liquid injection operations and another to gas injection operations. These equations are greatly simplified solutions to a more complicated mathematical expression which has already been simplified thanks to a number of assumptions including that the reservoir is 100% saturated with the injected fluid and it is infinite acting at all times. As a result, the answers obtained are approximations.

Why are we concerned with the radial distance to the point of potential endangerment?

Of special interest to the engineering review are the distances between an identified point with potential for endangerment (e.g., an improperly completed or unplugged well penetrating the injection formation) and one or more injection wells in the area. These inter-well distances are permanently defined when an operator drills a well, fixing in this way the field's well pattern.

One of these distances may be found to be the radius of endangering influence (REI) for the permit well or the field under study. In the Osage UIC program, the critical rate of accumulation is the injection rate (barrels per day) that, after 20 years of injection, would increase pressure at the nearest improperly completed or unplugged well to the extent that fluids would flow through the well into USDWs.

For a single injection well system, the critical rate of accumulation or environmentally safe rate of accumulation is computed using the distance to an identified point with potential for endangerment as the value for the radius required as input. Smaller radial distances will result in smaller allowed rates of accumulation.

Whenever continuity of the injection zone throughout the study area has been established, it will be necessary to estimate the combined pressure effect of several injection wells at points with potential for endangerment. Under this flow scenario, a multiple injection well system results.

How do we determine the maximum allowable injection pressure?

Maximum injection pressures are designed to minimize the risk of contamination of USDWs by preventing unintentional fracture propagation through confining formations adjacent to USDWs. This parameter may be need revisions during the life of a project to optimize injection operations.

The Osage UIC program may use either an assumed formation fracturing pressure gradient, or an instantaneous shut in pressure (ISIP) recorded during a well stimulation job to establish maximum injection pressure. Instantaneous shut in pressures (ISIPs) are representative of the pressure that would cause a fracture to reopen. These pressure readings may be available from the operator's files, especially in areas with aggressive well stimulation programs.

It may be necessary to modify the permitted maximum injection pressure based on updated information because formation fracture pressure may change with time. One approach for updating this information is to run a step rate test. The permits engineer may design and request a step rate test to estimate the new maximum allowed injection pressure from the rate and pressure data gathered.

United States Environmental Protection Agency
Underground Injection Control Program
1445 Ross Avenue
Dallas, TX 75202-2733

Annual Disposal Injection Well Monitoring Report

Operator:	**Owner:**

State: **County:** **Inventory Number:**
Qtr Section: **Section:** **Township:** **Range:** **Surface Location:**

Well Activity	**Type of Permit**	**Lease Name**	**Well Number**
Disposal No. of Wells:	☐ Individual ☐ Area		

	Injection Pressure		Total Volume Injected		Tubing-Casing Annulus Pressure		
Month / Year	Avg PSIG	Max PSIG	BBL	MCF	Min PSIG	Max PSIG	
JAN							
FEB							
MAR							
APR							
MAY							
JUN							
JUL							
AUG							
SEP							
OCT							
NOV							
DEC							

CERTIFICATOIN

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true accurate and complete. I am aware that there are significant penalties for submitting false information including the possibility of fine and imprisonment for knowing violations (Ref. 40 CFR 122.22)

Name and Official Title:	**Signature**	**Date Signed:**

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Dallas, TX 75202-2733

Annual Disposal Injection Well Monitoring Report

Operator:	**Owner:**

State: **County:** **Inventory Number:**
Qtr Section: **Section:** **Township:** **Range:** **Surface Location:**

Well Activity	**Type of Permit**	**Lease Name**	**Well Number**
	☐ Individual		
Disposal No. OF Wells:	☐ Area	USDW:	

	STATIC FLUID LEVEL (FEET SUBSURFACE)	
Month / Year	Tubing	Annulus
JAN		
FEB		
MAR		
APR		
MAY		
JUN		
JUL		
AUG		
SEP		
OCT		
NOV		
DEC		

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Name and Official Title:	**Signature**	**Date Signed:**

Bureau of Indian Affairs - Osage Agency

COMPLAINT FORM

1. Mail completed forms to: Bureau of Indian Affairs Osage Agency, P.O. Box 1539, Pawhuska, OK, 74056.
2. Fax completed forms to: (918) 287-5780.

☐ Confidential

Your Name:		Your Phone Number:	
Your Organization:		Your Business Phone Number:	
Your E-mail Address:			

Your Address:					
	Street	City	County	State	Zipcode

Describe Your Complaint (give as much detail as possible):
Address/Location of Complaint Site or Directions (give as much detail as possible):

Information About the Responsible Party (if known)			
Name	Company/Organization		
Phone Number(s):			
Street Address:			
City		State	Zipcode

Information About the Impacted Surface Owner (if known)			
Name	Company/Organization		
Phone Number(s):			
Street Address:			
City		State	Zipcode

Reference ID:

(office use only)